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February 14, 2017

By E-Mail & U.S. Mail
Pamela G. Monroe, Administrator
New Hampshire Site Evaluation Committee
21 South Fruit Street, Suite 10
Concord, NH 03301-2429
pamela.monroe@sec.nh.gov

Re: Docket No. 2015-06 – Joint Application of Northern Pass Transmission, LLC and Public Service Company of New Hampshire d/b/a Eversource Energy for a Certificate of Site and Facility

Dear Ms. Monroe:

Enclosed for filing in the above-referenced matter is the replacement, Pre-filed Testimony of Samuel Newell and Jurgen Weiss of The Brattle Group, Inc. ("Brattle"), together with a replacement of Brattle's report (Pre-filed Testimony Exhibit C), entitled "Electricity Market Impacts of the Proposed Northern Pass Transmission Project."

The replacement testimony and report includes a correction to the number for the baseline amount of capacity in northern New England and some text to clarify how Brattle handled northern New England's capacity and its effect on market clearing and to explain the revised results. The revision of this single number for the baseline supply changed the capacity market clearing results in scenarios 1 and 2 in Brattle's report, and impacted numbers in various tables and sections of the report. As such, please replace the Pre-filed Testimony of Samuel Newell and Jurgen Weiss and Brattle's report (Exhibit C) filed on December 30, 2016, with the enclosed replacement Pre-filed Testimony and replacement Exhibit C dated February 10, 2017.

Thank you.

Sincerely,

Thomas J. Pappas

TJP/scm - 2726162_1

Enclosure

cc: Peter C.L. Roth, Esq.
Elijah J. Emerson, Esq.
Distribution List

STATE OF NEW HAMPSHIRE
SITE EVALUATION COMMITTEE

DOCKET NO. 2015-06

JOINT APPLICATION OF NORTHERN PASS TRANSMISSION, LLC AND PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/A EVERSOURCE ENERGY FOR A CERTIFICATE OF SITE AND FACILITY

PREFILED DIRECT TESTIMONY OF

SAMUEL NEWELL AND JURGEN WEISS

ON BEHALF OF
COUNSEL FOR THE PUBLIC

Replacement to December 30, 2016 Testimony filed February 10, 2017

<u>Samuel Newell</u>

Q. Please state your name, position and your employer.

A. My name is Sam Newell. I am a Principal at The Brattle Group.

Q. Please summarize your education background and employment experience.

A. I earned a Ph.D. in technology management and policy from the Massachusetts Institute of Technology, an M.S. in materials science and engineering from Stanford University, and a B.A. in chemistry and physics from Harvard College. I have 18 years of experience supporting clients throughout the U.S. in regulatory, litigation, and business strategy matters regarding electricity wholesale markets, market design, generation asset valuation, demand response, integrated resource planning, and transmission planning. I have been at the Brattle Group since 2004. Prior to joining The Brattle Group, I was the Director of the Transmission Service at Cambridge Energy Research Associates. Before that, I was a Manager in the Utilities Practice at A.T. Kearney.

Q. Have you testified previously before the New Hampshire Site Evaluation Committee or other regulatory bodies?

A. I have not previously testified before the New Hampshire Site Evaluation Committee. I have testified numerous times before other regulatory and legal bodies: several state regulatory commissions, the Federal Energy Regulatory Commission, the Texas State Legislature, and the American Arbitration Association.

<u>Jurgen Weiss</u>

Q. Please state your name, position and your employer.

A. My name is Jurgen Weiss. I am a Principal at The Brattle Group.

Q. Please summarize your education background and employment experience.

A. I hold a B.A. in European Business Administration from the European Partnership of Business Schools (Reims, France and Reutlingen, Germany), an MBA from Columbia University and a Ph.D. in Business Economics from Harvard University. My professional experience includes approximately 20 years of consulting work, initially as an associate with Booz & Company (formerly Booz Allen & Hamilton), as an associate with The Brattle Group, as an independent economic expert, as a director with LECG, a founding managing director of Watermark Economics, as head of advisory services for Point Carbon, and finally as a principal with The Brattle Group.

Q. Have you testified previously before the New Hampshire Site Evaluation Committee or other regulatory bodies?

A. I have not previously testified before the New Hampshire Site Evaluation Committee. However, I have testified several times before both the Vermont Public Service Board and the Massachusetts Department of Public Service. I have also testified in two federal court proceedings.

Q. What is the purpose of your testimony?

A. The State of New Hampshire Counsel for the Public retained The Brattle Group ("Brattle") to provide economic analysis on the project that is the subject of this docket and the report titled "Cost-Benefit and Local Economic Impact Analysis of the Proposed Northern Pass Transmission Project" prepared by London Economics International ("LEI"). Brattle focused on NPT's potential impact on the New England wholesale energy and capacity markets, and resulting savings for New Hampshire electric customers. We also analyzed the value of potential greenhouse gas ("GHG") emission reductions from NPT. Our report is attached to our testimony as Exhibit A.

Q. Please describe the project that is the subject of this docket.

A. Northern Pass Transmission, LLC (the "Applicants") filed an application with the New Hampshire Site Evaluation Committee ("SEC") to build a 1,090 megawatt transmission line from the Canadian border at Pittsburg, New Hampshire to Deerfield, New Hampshire ("NPT") to transmit electricity likely generated from hydroelectric generation facilities operated by Hydro-Québec to serve load in New England. Our report analyzes the NPT's impacts on the New England wholesale electricity markets, New Hampshire retail electric ratepayers and GHG emissions in New England and New Hampshire.

Q. How did LEI approach its analysis of the NPT's impacts to New England wholesale electricity markets?

A. The premise of LEI's analysis is that (1) NPT will add new, low-carbon generation supply to the New England wholesale electricity market; (2) the added supply will lower wholesale market prices; (3) lower wholesale prices will lower retail electric providers' costs to purchase wholesale electricity to serve load in New Hampshire, even if they are not party to any transaction over NPT itself; and (4) the retail providers will pass through the savings to their customers. With respect to the value of potential GHG emission reductions, LEI's premise is that the imported energy from Hydro-Québec's hydroelectric facilities will reduce GHG emissions by displacing generation from natural gas-fired and other fossil fuel-fired resources in New England. LEI evaluates two main types of market impacts: price reductions in New England's wholesale energy market and price reductions in New England's wholesale capacity market. Retail electric companies must procure both energy and capacity in order to serve their electric customers.

Q. What are your conclusions regarding the LEI analysis?

A. We agree with LEI's overall premise but find that they did not address several important uncertainies that could reduce NPT's impacts—especially in the capacity market, which accounts for 90% of LEI's estimated benefits. One uncertain factor is the quantity and price of reliable capacity that Hydro-Québec would transmit via NPT. It is possible that ISO New England ("ISO-NE") does not qualify any (or all of the) capacity if Hydro-Québec cannot demonstrate that it has enough surplus capacity to reliably export power during the winter when its own system demand peaks. Furthermore, capacity that qualifies still may not clear the market. Clearing the capacity market depends on the price at which Hydro-Québec offers its capacity, which will be reviewed by ISO NE's Internal Market Monitor. Here, too, there is insufficient publicly-available data for us to determine whether and how much the Internal Market Monitor might mitigate NPT-related capacity offers.

Another crucial uncertainty is how competing suppliers respond to entry of NPT. If NPT is competing in state-sponsored clean energy solicitations, such as the one expected next year in Massachusetts, it could displace another similar transmission project or other clean energy resources. NPT could also displace existing capacity resources, including generation, imports, or demand response resources whose continued provision of capacity is sensitive to reductions in market prices. Similarly, NPT could displace a new capacity resource that would otherwise enter the market. We cannot perfectly predict how these market dynamics will work out, but estimating capacity displacement—and the prices at which displacement occurs—is important because it produces an offsetting effect on prices, reducing NPT's net impact.

Q. How did you address these uncertainties?

A. To address these uncertainties when estimating prices in a world with NPT compared to a world without NPT, we constructed four scenarios:

- **Scenario 1: NPT expands the supply of clean energy into New England without displacing other similar projects, and it provides 1,000 MW of capacity.** This scenario most closely corresponds to LEI's project case. However, this scenario takes into account changes in capacity market design and changes in market information revealed since the submission of the LEI Report. It also assumes, unlike LEI, that the addition of NPT capacity would cause some more expensive capacity resources not to clear the market that would have cleared in the absence of NPT. As a result, the net increase in capacity is substantially less than NPT's 1,000 MW, and the capacity price impact is partially mitigated. Unlike Scenario 2 below, we assume that while this "displaced" capacity does not clear the market in the initial years following NPT entry, it does not permanently retire and can thus provide capacity in the future.
- **Scenario 2: Similar to Scenario 1, but NPT induces 500 MW of existing generation capacity to retire.** In this scenario, we assume 500 MW of existing capacity that would have cleared absent NPT instead permanently retires when NPT enters due to the prospect of several years of reduced prices. We assume this 500 MW is spread throughout New England, with a third retiring in the Northern New England zone.
- **Scenario 3: NPT expands the supply of clean energy into New England without displacing other similar projects, but it does not provide any capacity.** This scenario reflects the possibility that Hydro-Québec imports via NPT may not qualify as a reliable capacity resource and/or may not clear the capacity market for the reasons noted above. Scenario 3 assumes the extreme case where zero NPT capacity qualifies and clears, recognizing that intermediate cases with partial qualification and clearing are also possible.
- **Scenario 4: NPT displaces competing clean energy projects, thus providing no more clean energy than if NPT were not constructed.** LEI and our Scenarios 1–3 assume NPT would expand the amount of clean energy in New England, reflecting the fact that NPT will access hydro resources in Québec that are not available now. In Scenario 4, we consider the possibility that NPT does not expand the amount of clean energy in New England, but rather that in the absence of NPT other similar clean energy resources would come online. Since several New England states are determined (and have laws on the books) to procure clean energy, NPT can be seen as one of several options to meet existing obligations. Absent NPT, one or several alternative options, such as the New England Clean Power Link through Vermont (which already has its siting permits), or incremental wind and photovoltaic resources in New England, might be developed

instead. Scenario 4 therefore compares a world with NPT to a world in which a similar competing project is built instead. This scenario allows us to consider the possibility that granting NPT a permit may only shift the delivery of future clean energy from some combination of regional renewable generation and hydro imports delivered over another line to the same amount of clean energy being delivered over this line through New Hampshire, and to ask what the relative electricity market-related benefits to New Hampshire would be in such a case.

Q. How did you approach estimating capacity market impact?

A. We model capacity market prices using a standard economic analysis of ISO-NE's annual capacity auctions using capacity demand and supply curves. Prices in the world without NPT are given by the intersection of our "base case" supply and demand curves; the world with NPT is similar except NPT-enabled capacity shifts the supply curve to the right and lowers the capacity market clearing price.

Q. What are your findings with regard to energy market impacts?

A. With respect to energy market impacts, we adopted LEI's analysis because we found that it appropriately captures the key characteristics of the New England energy market, including the relatively flat energy supply curve and future natural gas prices. We did, however, make adjustments for differences in the scenarios we constructed. For example, LEI found NPT's energy market benefits diminish starting in 2024 when NPT starts to displace new gas-fired combined-cycle generation that would otherwise enter the market. We found that displacement would occur two years later, so we extended the full energy market impact for longer (increasing the energy price suppression effects of NPT).

Q. What are your total estimated wholesale energy market savings for the New Hampshire ratepayers as a result of the NPT?

A. The following table contains the range of savings for New Hampshire that we estimated:

Table 1: Average Annual New Hampshire Customer Savings from 2020 to 2030

Scenarios	Energy Market Savings *$ million/year*	Capacity Market Savings *$ million/year*	Total Market Savings *$ million/year*
Scenario 1: NPT expands the supply of clean energy and clears 1,000 MW of capacity	**$10** ($8 - $10)	**$22** ($8 - $57)	**$32** ($16 - $67)
Scenario 2: Similar to Scenario 1 but NPT induces 500 MW of existing generation to retire	**$10** ($10 - $11)	**$11** ($5 - $32)	**$22** ($14 - $43)
Scenario 3: NPT expands the supply of clean energy but does not provide any capacity	**$12**	**-$7**	**$5**
Scenario 4: NPT displaces competing clean energy projects	**$0**	**$0**	**$0**

Notes: The values in parenthesis reflect the range of results from the sensitivity analysis. All savings are expressed in 2020 dollars.

Q. What are your estimated impacts to New Hampshire retail electric customers?

A. We assume the wholesale market impacts of NPT that reduce the costs of procuring energy and capacity by retail electric service providers would be fully passed through to retail customers, except for a small adjustment to account for customers that are not exposed to wholesale prices because they are covered by long-term contracts or self-supply. Across all of the scenarios and sensitivities we analyzed, we found that NPT could provide New Hampshire customers with retail rate savings of 0 to 0.55 cents/kWh on average from 2020 to 2030 (in constant 2020 dollar terms). These savings are in relation to 2016 baseline retail rates of roughly 18 cents/kWh. This would provide annual bill savings of $0 to $41 per residential customer (assuming 621 kWh per month) and $0 million to $67 million statewide each year on average over the 11-year period studied.

Q. What are your findings in regard to the NPT's impacts on greenhouse gas emissions?

A. One of the major potential benefits of NPT is that it could substantially lower greenhouse gas (GHG) emissions from the New England power sector. If NPT transmits hydro power from Québec without displacing the development of other clean resources, most of the power transmitted would displace natural gas-fired generation in New England. Based on LEI's energy and emissions analysis, the addition of NPT would eliminate approximately 3 million metric tons of carbon dioxide-equivalent emissions per year, an 8% reduction relative to New England's current electric sector GHG emissions. The net GHG emissions savings of NPT could be substantially less if Hydro-Québec does not in fact increase its hydro generation to serve New England load but instead diverts power that would otherwise have been exported to New York or elsewhere and if this diverted power is replaced with resources in those markets with emissions rates above those assumed by LEI.

Assuming Hydro-Québec is able to increase hydro generation to supply power over NPT and thereby reduce global GHG emissions by approximately 3 million metric tons per year, a key question for New Hampshire is how to value those reductions. If NPT displaces fossil generation and reduces GHG emissions by 3 million tons per year, the overall value of emissions reductions due to NPT could be assessed at $140 to $340 million per year, reflecting the avoided cost of alternative GHG emissions reduction options. Even if New Hampshire does in fact value carbon abatement at the avoided cost of alternative abatement measures, it would not be appropriate to count the full amount of NPT's carbon abatement as a benefit for New Hampshire since emissions reductions occur on a regional basis and since contractual arrangements could allocate GHG benefits to different states. Allocating 10% or $14 to $34 million annually of the GHG benefits of NPT to New Hampshire would be appropriate.

However, this is only one possible proxy for the value of GHG emissions reductions to New Hampshire, since PSNH does not in fact have any particular requirement to reduce GHG emissions. Absent a legally binding mandate to reduce GHG emissions, one can argue that the avoided cost of GHG emissions reductions is not a valid measure of the value New Hampshire places on greenhouse gas savings and in fact the value placed on GHG emissions reductions could be quite low.

Q. Does this conclude your testimony?

A. Yes.

EXHIBITS

A. Resume of Samuel Newell

B. Resume of Jurgen Weiss

C. Electricity Market Impacts of the Proposed Northern Pass Transmission Project.

Electricity Market Impacts of the Proposed Northern Pass Transmission Project

PREPARED FOR

The New Hampshire Counsel for the Public

PREPARED BY

Samuel Newell
Jurgen Weiss

Revised on February 10, 2017

THE Brattle GROUP

This report was prepared for the State of New Hampshire Counsel for the Public. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group or its clients.

Table of Contents

Executive Summary

Introduction

Northern Pass Transmission, LLC (Applicants) filed an application with the New Hampshire Site Evaluation Committee to build a 1,090 megawatt transmission line (known as Northern Pass or NPT) from the Canadian border at Pittsburg, New Hampshire to Deerfield, New Hampshire, to transmit electricity likely generated from hydroelectric generation facilities operated by Hydro-Québec to serve load in New England. The State of New Hampshire Counsel for the Public retained The Brattle Group (Brattle) to provide an economic analysis of NPT and to review the report titled "Cost-Benefit and Local Economic Impact Analysis of the Proposed Northern Pass Transmission Project" prepared by London Economics, International (LEI).[1]

Specifically, Brattle focused on NPT's potential impact on the New England wholesale energy and capacity markets, and the resulting savings for New Hampshire electric customers. We also analyzed the value of potential greenhouse gas (GHG) emissions reductions from NPT. We did not analyze all of NPT's costs and benefits, however. Our understanding is that other experts are evaluating other types of costs and benefits of NPT to New Hampshire.

Below, we present our approach and findings, including our conclusions about the LEI Report. We address customer impacts first, followed by GHG emissions impacts.

LEI's Approach

The premise of LEI's analysis is that (1) NPT will add new, low-carbon generation supply to the New England wholesale electricity market; (2) the added supply will lower wholesale market prices; (3) lower wholesale prices will lower retail electric providers' costs to purchase wholesale electricity to serve load in New Hampshire, even if they are not party to any transaction over NPT itself; and (4) the retail providers will pass through the savings to their customers. With respect to the value of potential GHG emission reductions, LEI's premise is that the imported energy from Hydro-Québec's hydroelectric facilities will reduce GHG emissions by displacing generation from natural gas-fired and other fossil fuel-fired resources in New England.

LEI evaluated two main types of electricity market impacts: price reductions in New England's wholesale energy market and price reductions in New England's wholesale capacity market. Retail electric companies must procure both energy and capacity to serve their electric customers. "Energy" is what retail customers consume directly when they use electricity. Retail customers use "capacity" indirectly. Capacity is the capability to produce electricity at any time

1 Frayer, Julia, Eva Wang, Ryan Hakim, and Adnan Cheema (2015), *Cost-Benefit and Local Economic Impact Analysis of the Proposed Northern Pass Transmission Project*, prepared for Northern Pass Transmission, LLC, October 16, 2015. ("LEI Report")

to meet expected or unexpected peak demands, such as energy needs on the hottest day of the year. Both energy and capacity markets are administered by the New England independent system operator, ISO New England (ISO-NE).

Uncertainties Not Addressed By LEI

We agree with LEI's overall premise but find that they did not address several important uncertainties that could reduce NPT's impacts—especially in the capacity market, which accounts for 90% of LEI's estimated benefits. One uncertain factor is the quantity and price of capacity that Hydro-Québec would transmit via NPT. It is possible that ISO-NE does not qualify any (or all of the) capacity if Hydro-Québec cannot demonstrate that it has enough surplus capacity to reliably export power during the winter when its own system demand peaks. There is limited public information available and no information provided by the Applicants in this proceeding for us to determine how much capacity will qualify, if any. Furthermore, capacity that qualifies still may not clear the market. Clearing the capacity market depends on the price at which Hydro-Québec offers its capacity, which will be reviewed by ISO-NE's Internal Market Monitor. To prevent low offers supported by out-of-market payments from artificially suppressing market prices, the Internal Market Monitor can mitigate offers upward to ensure that they reflect the full cost of providing that capacity. If the Internal Market Monitor decides to require NPT-associated resources to offer at a higher price, the resources may not clear the capacity market, which would result in NPT having no impact on capacity prices; or it could result in a lower impact of NPT on capacity prices if NPT's mitigated bid sets the capacity price. Here, too, there is insufficient publicly available data for us to determine whether and how much the Internal Market Monitor might mitigate NPT-related capacity offers.

Another crucial uncertainty is how competing suppliers respond to the entry of NPT. If NPT is competing in state-sponsored clean energy solicitations, such as the one expected next year in Massachusetts, it could displace another similar transmission project, such as the New England Clean Power Link running through Vermont, or other clean energy resources. NPT could also displace existing capacity resources, including generation, imports, or demand response resources whose continued provision of capacity is sensitive to reductions in market prices. For example, if NPT adds capacity and lowers the capacity price, an existing oil-fired steam plant may no longer clear the market; the plant's owner may decide to retire the plant, mothball the plant, or continue to operate the plant without taking on a capacity supply obligation and the costs and risks that entails. Similarly, NPT could displace a new capacity resource that would otherwise enter the market. We cannot perfectly predict how these market dynamics will work out, but estimating capacity displacement—and the prices at which displacement occurs—is important because it produces an offsetting effect on prices, reducing NPT's net impact. We estimate the impact of supplier response by incorporating more up-to-date market information than was available to LEI at the time of its filing and by constructing scenarios and sensitivities to reflect relevant uncertainties.

Four Scenarios to Address Uncertainties

To address these uncertainties when estimating prices in a world with NPT compared to a world without NPT, we constructed four scenarios (presented in descending order of market price impacts due to NPT):

- **Scenario 1: NPT expands the supply of clean energy into New England without displacing other similar projects, and it provides 1,000 MW of capacity.** This scenario most closely corresponds to LEI's project case. However, this scenario takes into account changes in capacity market design and changes in market information revealed since the submission of the LEI Report. It also assumes, unlike LEI, that the addition of NPT capacity would cause some more expensive capacity resources not to clear the market that would have cleared in the absence of NPT. As a result, the net increase in capacity is substantially less than NPT's 1,000 MW, and the capacity price impact is partially mitigated. Unlike Scenario 2 below, we assume that while this "displaced" capacity does not clear the market in the initial years following NPT entry, it does not permanently retire and can thus provide capacity in the future.
- **Scenario 2: Similar to Scenario 1, but NPT induces 500 MW of existing generation capacity to retire.** In this scenario, we assume 500 MW of existing capacity that would have cleared absent NPT instead permanently retires when NPT enters due to the prospect of several years of reduced prices. We assume this 500 MW is spread throughout New England, with a third retiring in the Northern New England zone.
- **Scenario 3: NPT expands the supply of clean energy into New England without displacing other similar projects, but it does not provide any capacity.** This scenario reflects the possibility that Hydro-Québec imports via NPT may not qualify as a reliable capacity resource and/or may not clear the capacity market for the reasons noted above. Scenario 3 assumes the extreme case where zero NPT capacity qualifies and clears, recognizing that intermediate cases with partial qualification and clearing are also possible.
- **Scenario 4: NPT displaces competing clean energy projects, thus providing no more clean energy than if NPT were not constructed.** LEI and our Scenarios 1–3 assume NPT would expand the amount of clean energy in New England, reflecting the fact that NPT will access hydro resources in Québec that are not available now. In Scenario 4, we consider the possibility that NPT does not expand the amount of clean energy in New England, but rather that in the absence of NPT other similar clean energy resources would come online. Since several New England states are determined (and have laws on the books) to procure clean energy, NPT can be seen as one of several options to meet existing obligations. Absent NPT, one or several alternative options, such as the New England Clean Power Link through Vermont (which already has its siting permits), or incremental wind and photovoltaic resources in New England, might be developed instead. Scenario 4 therefore compares a world with NPT to a world in which a similar competing project is built instead. This scenario allows us to consider the possibility that granting NPT a permit may only shift the delivery of future clean energy from some combination of

regional renewable generation and hydro imports delivered over another line to the same amount of clean energy being delivered over this line through New Hampshire, and to ask what the relative electricity market-related benefits to New Hampshire would be in such a case.

Approach to Analyzing Wholesale Electricity Markets

To estimate NPT's impacts on wholesale prices and customers rates, we modeled prices with NPT versus prices without NPT in each of these scenarios. In Scenarios 1 and 2, NPT reduces both energy and capacity market prices. In Scenario 3, NPT reduces energy prices but not capacity prices (capacity prices may actually increase as energy prices decrease, for reasons explained below). In Scenario 4, NPT does not materially affect either the energy or capacity market compared to the world without NPT.

Capacity Market

We model ***capacity market*** prices using a standard economic analysis of ISO-NE's annual capacity auctions using capacity demand and supply curves. Prices in the world without NPT are given by the intersection of our "base case" supply and demand curves; the world with NPT is similar except NPT-enabled capacity shifts the supply curve to the right and lowers the capacity market-clearing price.

For technical readers, the details of our model that most affect the results are the following: demand curves reflect those set by ISO-NE based on a pre-specified, downward-sloping shape that is centered on a reliability-based target quantity and a benchmark price corresponding to the estimated cost of capacity from new natural gas-fired generation. We adopt ISO-NE's latest demand curves for the whole system and for Northern New England (specifying price reductions when Northern New England capacity exceeds local needs plus transmission limits for exporting to the rest of the system) and shift them rightward over time based on ISO-NE's escalating summer peak load forecast. On the supply side, supply curves represent the quantities and prices at which all existing, planned, and potential new resources are willing to take on a capacity supply obligation. They are upward sloping with the lower part of the curve defined by the prices at which existing capacity resources are willing to stay in the market; the high end is defined by the price at which new natural gas-fired generation will enter the market. To determine the quantity of existing and planned capacity submitting offers, we assume that all resources cleared in ISO-NE's latest auction will continue to offer capacity except for 200 MW of old generation capacity that we assume will retire each year, consistent with historical average retirement rates. Most of the remaining existing capacity will offer its capacity at relatively low prices. However, marginal oil- and gas-fired capacity may offer at higher prices indicating its intent to exit the market if the price falls below its offer. Our exit prices are based on reports from the Internal Market Monitor indicating that the average offer from about 5,000 MW of marginal oil- and gas-fired capacity clearing in the last auction was $5.50/kW-month.[2] These resources are submitting higher exit prices than they did historically because ISO-NE recently implemented a performance penalty mechanism that exposes older, less efficient resources to substantial costs and risks if they take on a capacity supply obligation. ISO-NE's penalty rates are scheduled to increase over the next several years, so we project the marginal oil- and gas-fired resources' offer prices to increase accordingly. Regarding the entry price for new supply at the top of the supply curve, we assume an offer price of $9/kW-month (increasing with inflation) based on cleared offers observed in the last two capacity auctions and on recent studies by ISO-NE.[3]

In the first years of our base case capacity forecast, we project capacity prices to remain below $7/kW-month (the clearing price in the latest capacity auction) due to recent capacity additions and planned changes to the ISO-NE demand curves. The low prices leave little room for the addition of NPT to reduce prices further, since at lower prices marginal oil- and gas-fired capacity will likely exit and keep prices from falling below about $6/kW-month. Over time, our base case prices rise with demand growth, steady retirements, and increasing penalty rates, reaching the assumed new entry price of $9/kW-month (in 2020 dollars) starting in 2026, then remain at that level as capacity enters to meet ongoing demand growth. The price reduction caused by NPT is greatest when base case prices are at the new entry price and additional supply from NPT prevents prices from rising to that level by maintaining surplus capacity for an additional one to three years.

It is important to recognize that actual prices in any individual auction may differ from our projections due to unexpected changes in market conditions. We also recognize, even more importantly for this analysis, that the impact of NPT is uncertain because the supply curve is uncertain. We therefore analyze the sensitivity of our results by varying key supply curve assumptions over a range of plausible values. Specifically, we tested the following assumptions: the amount of retirements occurring in the base case (from 0 to 400 MW/year); the assumed offer prices below which existing marginal oil- and gas-fired generation will exit; and the prices at which new natural gas-fired generation will enter (from $7 to $12/kW-month). Entry prices are particularly important because they set prices in the future when load growth and retirements raise prices high enough to attract new generation, the need for which NPT may delay.

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2 ISO-NE/NEPOOL (2015), Joint Testimony of Jeffery D. McDonald and Robert V. Laurita on behalf of ISO New England Inc., before the Federal Energy Regulatory Committee, in the matter of ISO New England Inc. and New England Power Pool, Docket No. ER15-1650-000, May 1, 2015. Attachment to Letter to The Honorable Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, Electronic filing: ISO New England Inc. and New England Power Pool, Docket No. ER15-1650-000, Market Monitoring-Related Capacity Market Changes, May 1, 2015, pp. 11–12. ("McDonald/Laurita Testimony") Available at: https://www.iso-ne.com/static-assets/documents/2015/05/er15-1650-000_mkt_monitoring-related_capacity_mkt_chgs.pdf

3 See Section III.A.2 for discussion of the sources we reviewed to inform the entry price for new supply.

Energy Market

With respect to ***energy*** market impacts, we adopted LEI's analysis because we found that it appropriately captures the key characteristics of the New England energy market, including the relatively flat energy supply curve and future natural gas prices. We did, however, make adjustments for differences in the scenarios we constructed. For example, LEI found NPT's energy market benefits diminish starting in 2024 when NPT starts to displace new natural gas-fired combined-cycle generation that would otherwise come online and add low-cost energy to the energy market. We found that this displacement would start two years later, so we extended the full energy market impact for longer.

Similar to LEI, our study time horizon is from 2020 to 2030. After 2030, NPT would continue to operate and may still provide value for parties to transactions across the line, but NPT's impacts on wholesale prices will have largely attenuated. By then, NPT will have displaced an equivalent amount of traditional generation resources if not clean energy resources. LEI agreed with this, observing that "market price impacts will dissipate with time as the market recalibrates to a balanced supply-demand condition."[4]

IMPACTS ON NEW HAMPSHIRE ELECTRIC CUSTOMERS' BILLS

Our Estimates

We assume the wholesale market impacts of NPT that reduce the costs of procuring energy and capacity by retail electric service providers would be fully passed through to retail customers, except for a small adjustment to account for customers that are not exposed to wholesale prices because they are covered by long-term contracts or self-supply.[5] Across all of the scenarios and sensitivities we analyzed, we found that NPT could provide New Hampshire customers with retail rate savings of 0 to 0.55 ¢/kWh (in 2020-dollar terms) on average from 2020 to 2030. These savings are in relation to 2016 baseline retail rates of roughly 18 ¢/kWh. Per household, annual bill savings could be as little as zero or as great as $41.[6]

Aggregating over all electricity customers in New Hampshire, annual bill savings could be between zero and $67 million, with the low end corresponding to Scenario 4 and the high end corresponding to Scenario 1 at the top of the sensitivity range. These total statewide customer savings are shown in Table ES-1.

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4 LEI Report, p. 37.

5 This is a small adjustment, with only 4-9% of energy demand and 4-7% of peak load that are not exposed to wholesale prices. LEI Report, p. 111.

6 We assume 621 kWh per month. U.S. Energy Information Administration (2016), 2015 Average Monthly Bill—Residential, accessed December 2016. http://www.eia.gov/electricity/sales_revenue_price/pdf/table5_a.pdf.

Table ES-1: Average Annual New Hampshire Customer Savings from 2020 to 2030

Scenarios	Energy Market Savings *$ million/year*	Capacity Market Savings *$ million/year*	Total Market Savings *$ million/year*
Scenario 1: NPT expands the supply of clean energy and clears 1,000 MW of capacity	**$10** ($8 - $10)	**$22** ($8 - $57)	**$32** ($16 - $67)
Scenario 2: Similar to Scenario 1 but NPT induces 500 MW of existing generation to retire	**$10** ($10 - $11)	**$11** ($5 - $32)	**$22** ($14 - $43)
Scenario 3: NPT expands the supply of clean energy but does not provide any capacity	**$12**	**-$7**	**$5**
Scenario 4: NPT displaces competing clean energy projects	**$0**	**$0**	**$0**

Notes: Values in parentheses reflect the range of sensitivity analysis results described in Section IV.A. All savings are expressed in 2020 dollars.

In Scenarios 1, 2, and 3, estimated statewide customer savings from NPT's ***energy market*** price impacts are between $8 to $12 million; in Scenario 4 there is no impact since there is no net change in energy supply in that scenario. The narrow range of energy market impacts across Scenarios 1, 2, and 3 is driven by the fact that energy prices are not very sensitive to changes in supply; they are more sensitive to changes in natural gas price, which we assume to be unchanged with the addition of NPT. These estimates are conservatively low because they do not account for rare but extreme market conditions, including natural gas supply shortages, which could increase the energy market benefit of NPT (in Scenarios 1–3).

Capacity market impacts are potentially larger but are also much more uncertain than energy market impacts. We estimate that NPT's capacity market impacts on New Hampshire customers' annual electricity costs could range from a $57 million decrease in the best case to a $7 million cost increase at worst. The top of the range corresponds to Scenario 1 with the upper bound assumption on the cost of new entry ($12/kW-mo). This case shows the greatest benefits of NPT because it assumes the maximum possible amount of capacity qualifies and clears, that no existing capacity retires in response, and that when NPT delays the increase of capacity prices to the level needed to attract new entry, it does so to maximum effect. NPT's suppression of capacity prices is more pronounced in the Northern New England capacity zone than in the rest of the system due to an excess of local capacity relative to local needs and export limits. However, benefits fall from $57 million to $22 million by simply reducing the assumed cost of new entry to our expected value of $9/kW-month, still under Scenario 1. In Scenario 2, benefits fall to $11 million because the assumed 500 MW of permanent retirements reduces the ***net*** addition of capacity to the system to only half as much as in Scenario 1. The worst case is Scenario 3, in which NPT does not transmit any capacity into the New England market, but it still transmits energy and reduces energy prices; with lower energy prices, new natural gas-fired combined-cycle entrants have to earn more in the capacity market to be willing to enter the market. This sets capacity prices at a higher level in the later years than in the base case, raising customer costs (but not enough to fully offset the energy market benefit). Finally, in Scenario 4 there are no capacity benefits because NPT provides no more capacity than alternative projects would provide.

One other important point that LEI did not address is that any customer savings based on wholesale price impacts largely reflect wealth transfers, not economic value created; price reductions that benefit customers almost symmetrically reduce suppliers' revenues. The reduction in revenues could lead the most marginal suppliers to exit the market, as we have considered in our scenarios. The vast majority of suppliers would not exit but would earn diminished revenues, with possible economic consequences for New Hampshire and New England beyond wholesale market prices. Wealth would be transferred from generators to customers all over New England with disproportionate generator losses in New Hampshire because New Hampshire is a net exporter of energy and capacity.

Comparison to LEI's Estimates

As noted above, LEI did not address any of the supply response or other key uncertainties we found to be important in our scenario and sensitivity analyses. Instead, LEI optimistically assumed that 1,000 MW of NPT capacity would qualify and clear in the capacity auction, that almost no existing resources would exit in response to NPT (corresponding to an unrealistic vertical supply curve), and that [redacted]. LEI also did not consider the possibility that NPT might simply displace other similar clean energy projects, as in our Scenario 4.

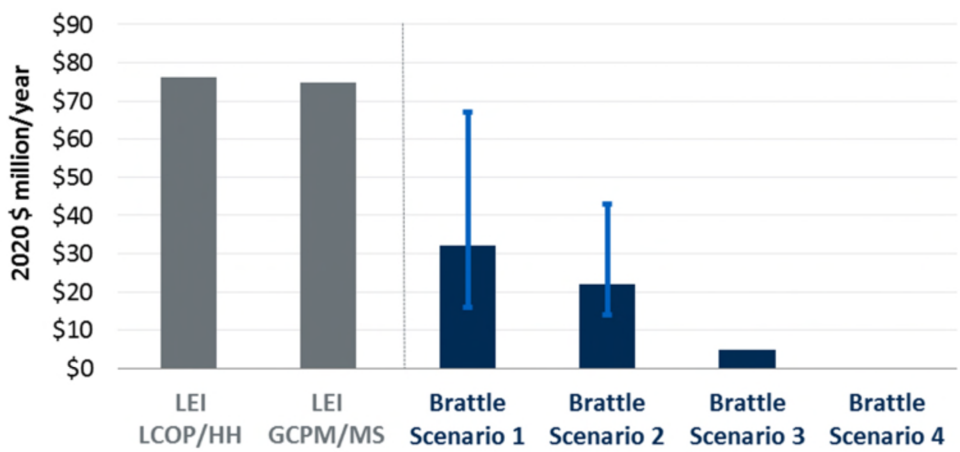
LEI's estimate is also outdated in ways that contribute to overstating NPT's likely benefits. Since LEI conducted its analysis in 2015, the capacity market has fundamentally changed. Demand has decreased and additional capacity has entered the market, depressing expected capacity prices even without NPT. Also, evidence of the availability of low-cost new generation suggests that capacity prices will remain low into the future. Meanwhile, capacity market offers observed in the most recent auctions (as reported by the Internal Market Monitor) suggest that existing generators may exit the market if prices fall much further, thus limiting any downward impact of NPT on prices. These changes suggest that supply curves have become flatter and more elastic. Indeed, ISO-NE has attested that the capacity supply curves have become much more elastic due to the new performance penalty regime described above.[7] Consequently, capacity market prices are likely to remain within a narrower and lower band than the [redacted] (in 2020

7 ISO-NE/NEPOOL (2016a). Prepared Testimony of Christopher Geissler and Matthew White on behalf of ISO New England Inc., before the Federal Energy Regulatory Commission, in the matter of ISO New England Inc. and New England Power Pool Participants Committee, ER16-1434-000, April 15, 2016. Attachment to Letter to The Honorable Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, Electronic filing: ISO New England Inc. and New England Power Pool Participants Committee, Docket No. ER16-1434-000, Demand Curve Design Improvements, April 15, 2016, pp. 120–21. ("Geissler/White Testimony") Available at: https://www.iso-ne.com/static-assets/documents/2016/04/er16-1434-000.pdf

dollars) range LEI estimated, and prices are unlikely to be as sensitive to supply additions as LEI suggests.

For these reasons, LEI's estimated annual customer savings of $75 to $76 million over 11 years are optimistically high and reflect the relatively inconsequential uncertainty related to natural gas prices, without addressing the more important uncertainties in capacity market dynamics that we addressed in our scenarios and sensitivities (shown as blue error bars in Figure ES-1 below).[8]

Figure ES-1: Average Annual New Hampshire Customer Savings



Notes: We converted the results LEI presents in Figure 1 of their report from nominal dollars to constant 2020 dollars and accounted for the price-insulating effect of long-term contracts so that LEI's results can be compared to ours. Error bars reflect the range of sensitivity analysis results.

Estimated GHG Emissions Impacts

One of the major potential benefits of NPT is that it could substantially lower greenhouse gas (GHG) emissions from the New England power sector. If NPT transmits hydro power from Québec without displacing the development of other clean resources, most of the power transmitted would displace natural gas-fired generation in New England. Based on LEI's energy and emissions analysis, the addition of NPT would eliminate approximately 3 million metric tons

8 The LEI wholesale market benefits for New Hampshire reported here appear lower than the $81.0 to $82.5 million annual wholesale market impact presented in Figure 1 of their report because we converted their results from nominal dollars to 2020 dollars (which reduces the amounts by about 5%) and accounted for the price-insulating effect of long-term contracts, as LEI did when translating wholesale market savings to customer retail savings (which further reduces the amounts by about 2.5%). These adjustments are necessary to present our results and LEI's results in comparable terms.

of carbon dioxide-equivalent emissions per year, an 8% reduction relative to New England's current electric sector GHG emissions.[9]

This net impact of NPT on global GHG emissions depends on the incremental sources of energy Hydro-Québec uses for exports via NPT. LEI assumes that Hydro-Québec sources the power primarily from incremental hydro generation from existing facilities or from those under construction (hydro is already Hydro-Québec's dominant source of energy) [redacted].[10,11] Existing hydro power plants emit relatively small amounts of greenhouse gases, methane specifically, due to the decomposition of organic material in the pond behind the dam. Greenhouse gas emissions from new hydro facilities can be substantially greater from the loss of carbon absorption and from initially higher methane emissions from flooded vegetation. LEI's estimated emissions rate for power flowing over NPT of approximately 0.5 million metric tons per year is based on the estimated lifecycle emissions for a new large hydro facility in Quebec of 136 lbs/MWh.[12]

The net GHG emissions savings of NPT could be substantially less under two possible circumstances. One is if Hydro-Québec does not increase its hydro generation to serve New England but instead diverts power that would otherwise serve New York or elsewhere, and the power is replaced with fossil-fired generation. Given the lack of sufficiently complete information about Hydro-Québec's participation in electricity markets throughout the northeast U.S. and eastern Canada, this possibility cannot be ruled out. A second possibility for GHG savings to be lower than estimated by LEI is if NPT displaces the development of a similar clean energy resource in New England, such as an alternative transmission line transporting the same incremental electricity as described in Scenario 4 above. Conceivably, GHG emissions could even increase if NPT displaced alternative clean energy with emissions rates below the hydro emissions rates assumed by LEI for NPT, such as Class I renewables solar PV and wind.

Assuming Hydro-Québec is able to increase hydro generation to supply power over NPT and thereby reduce global GHG emissions by approximately 3 million metric tons per year, a key question for New Hampshire is how to value those reductions. LEI suggested using the "social

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9 2014 ISO-NE CO_2 emissions were 39.3 MMT. ISO New England (2016), 2014 ISO New England Electric Generator Air Emissions Report, System Planning, January 2016, p. 18. Available at: https://www.iso-ne.com/static-assets/documents/2016/01/2014_emissions_report.pdf

10 Delivery Performance Agreement by and between Hydro Renewable Energy Inc. and Northern Pass Transmission LLC, Execution Copy, January 22, 2016.

11 Power Purchase Agreement by and between Public Service Company of New Hampshire d/b/a Eversource Energy as Buyer and Hydro Renewable Energy Inc. as Seller, Execution Copy, June 17, 2016, Attachment A to Prepared Testimony of James G. Daly, before the New Hampshire Public Utilities Commission, in the matter of the Petition of Public Service Company of New Hampshire D/B/A Eversource Energy for Approval of a Power Purchase Agreement, Docket No. DE 16-XXX, June 28, 2016.

12 LEI Report, pp. 67–68.

cost of carbon" (SCC), based on the United States federal government's estimate of global damages from incremental GHG emissions, net of Regional Greenhouse Gas Initiative (RGGI) prices, as a measure of the value of avoided GHG emissions. Since the SCC is a metric used for policy evaluation at the U.S. federal policy level, it provides a natural metric for assessing the value of GHG emissions reductions. However, the SCC is a measure of the global cost of an incremental ton of GHG emissions and hence unrelated to New Hampshire's willingness to pay for any emissions reductions.

We cannot observe New Hampshire's willingness to pay for GHG emissions reductions directly but might infer something about it based on New Hampshire's existing policy commitments and the costs New Hampshire accepts to meet those commitments. For one, New Hampshire participates in RGGI, which requires all emitting generators in New Hampshire to buy allowances in order to pollute. Recent allowance prices have been in the range of \$4 to \$9 per metric ton of CO_2, suggesting, at a minimum, a willingness to pay in this range.

Separately, like other New England states, New Hampshire in 2009 established a goal to reduce its GHG emissions by 80% relative to 1990 emissions by 2050. Meeting this goal will likely require procuring additional clean energy resources, such as onshore wind, solar PV, *etc.*, at a premium over current wholesale market prices. Onshore wind is likely the lowest cost alternative to deploy on a large scale in the absence of NPT. We estimate its incremental cost, net of energy and capacity revenues, to be approximately \$20 to \$50 per MWh (assuming no new transmission is needed). This implies a cost of approximately \$40 to \$100 per metric ton of GHG emissions avoided. Thus, if NPT displaces fossil generation and reduces GHG emissions by 3 million tons per year, the overall value of emissions reductions due to NPT could be assessed at \$140 to \$340 million per year, reflecting the avoided cost of alternative GHG emissions reduction options.

Even if New Hampshire does in fact value carbon abatement at the avoided cost of alternative abatement measures, it would not be appropriate to count the full amount of NPT's carbon abatement as a benefit for New Hampshire since emissions reductions occur on a regional basis and since contractual arrangements could allocate GHG benefits to different states. Specifically, Hydro-Québec is offering Public Service of New Hampshire (PSNH) a power purchase agreement via NPT that would provide PSNH about 10% of the power flowing over NPT at the New England energy market price and would include the associated environmental attributes. Under this arrangement, allocating 10% of the New England-wide GHG benefits of NPT to New Hampshire would be appropriate, which is \$14 to \$34 million annually. (This is true even in our Scenario 4, where NPT and the agreement with PSNH occur instead of a competing project with which PSNH does not have a special agreement.) Alternatively, if the power purchase agreement is not approved by the New Hampshire Public Utilities Commission,[13] the rights to clean energy might be assigned entirely to parties outside New Hampshire, and New Hampshire would enjoy no GHG reduction credit.

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[13] See: http://www.puc.state.nh.us/Regulatory/Docketbk/2016/16-693.html

However, this is only one possible proxy for the value of GHG emissions reductions to New Hampshire, since PSNH does not in fact have any particular requirement to reduce GHG emissions or procure any particular amount of clean energy. Absent a legally binding mandate to reduce GHG emissions—New Hampshire's 80% reduction target is a goal, not a legally binding mandate—one can argue that the avoided cost of GHG emissions reductions is not a valid measure of the value New Hampshire places on greenhouse gas savings and in fact the value placed on GHG emissions reductions could be lower, perhaps substantially lower, than either the $40 to $100/ton estimated above or any measure of the social cost of carbon.

Finally, we recognize the possibility that NPT could affect allowance prices under RGGI, which in turn could lead to additional energy price impacts as well as a partially offsetting effect through lower revenues generated through auctions of RGGI allowances. However, due to the uncertainties related to the evolution of the RGGI Model Rule in the future, and in particular the possibility that the RGGI Model Rule might be tightened in response to emissions reductions such as those resulting from NPT, which could eliminate any impact of NPT on RGGI allowance prices, we decided not to quantify any possible impact of NPT on New Hampshire customers through RGGI and note that LEI did not assess this possibility either.

Conclusions

We conclude that NPT could reduce New Hampshire customer rates between 0 and 0.55 cents per kilowatt-hour (¢/kWh) and save customers between $0 and $67 million per year (in 2020 dollar terms) on average between 2020 and 2030. This wide range reflects uncertainties we cannot resolve at this time. How much New Hampshire customers will save depends on the difference in prices between a world with NPT in place and a world without it. That difference depends strongly on many unknowns about the actions of parties other than the Applicants: whether other similar clean resources are less likely to develop if NPT proceeds, for example in Massachusetts' open solicitation for clean energy; how much capacity Hydro-Québec will be able to transmit (or sell) into the New England market; and, if NPT does transmit capacity that lowers prices, how other suppliers in the capacity market will respond and create an offsetting effect.

Regarding GHG emissions, one can make the qualitative point that if NPT is approved and constructed it will deliver relatively clean energy, avoiding as much as 8% of New England's current electric sector GHG emissions. It is more difficult to determine exactly how GHG emissions would evolve if the line were not built, since that depends on actual and but-for behavior of Hydro-Québec and clean energy buyers in New England. Specifically, it would depend on whether Hydro-Québec would end up selling a similar amount of hydro power delivered through an alternative line and/or on whether New England buyers would procure an equivalent amount of clean energy resources, either from Hydro-Québec or alternative sources. It is also difficult to place a dollar value on emissions savings from a New Hampshire perspective. Depending on whether New Hampshire values emissions abatement at the avoided cost of alternative abatement measures or not at all, the annual value to New Hampshire could be as high as $34 million per year and in an extreme case as low as $0.

I. Background

A. Introduction

Northern Pass Transmission, LLC (Applicants) filed an application with the New Hampshire Site Evaluation Committee to build a 1,090 megawatt transmission line (known as Northern Pass or NPT) from the Canadian border at Pittsburg, New Hampshire to Deerfield, New Hampshire to transmit electricity likely generated from hydroelectric generation facilities operated by Hydro-Québec to serve load in New England. The State of New Hampshire Counsel for the Public retained The Brattle Group (Brattle) to provide an economic analysis of NPT and to review the report titled "Cost-Benefit and Local Economic Impact Analysis of the Proposed Northern Pass Transmission Project" prepared by London Economics, International (LEI).[14]

Specifically, Brattle focused on NPT's potential impact on the New England wholesale energy and capacity markets, and the resulting savings for New Hampshire customers assuming the line is placed in service in January 2020.[15] We also analyzed the value of potential greenhouse gas (GHG) emissions reductions from NPT. We did not conduct a comprehensive analysis of NPT's costs and benefits. We understand that other experts in this proceeding are evaluating other types of costs and benefits of NPT to New Hampshire.

B. The New England Electricity Market and Customer Rates

To understand how NPT could affect wholesale electricity prices and customers' retail rates, it is helpful to start with a short primer on the wholesale electricity markets and how they relate to retail rates. There are actually two different wholesale electricity markets NPT could affect: the wholesale energy market and the wholesale capacity market, both of which are administered by ISO New England (ISO-NE). Retail electric providers must procure both energy and capacity from these markets in order to serve their electric customers.

"Energy" is what customers consume directly when they use electricity every hour, and the units are kilowatt-hours (kWh) or megawatt-hours (MWh). The role of the wholesale energy market is to allow retail electric providers to procure the energy being consumed by their customers from the lowest-variable-cost set of resources available each hour. Renewable generation and hydropower tend to have little or no variable cost since most of them burn no fuel, but their supply is limited. The next cheapest source of energy in New England is nuclear power, usually followed by natural gas-fired generation, then coal, then oil, depending on varying fuel prices;

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14 Frayer, Julia, Eva Wang, Ryan Hakim and Adnan Cheema (2015), Cost-Benefit and Local Economic Impact Analysis of the Proposed Northern Pass Transmission Project, prepared for Northern Pass Transmission, LLC, October 16, 2015. ("LEI Report")

15 LEI assumed the line is placed in service in May 2019. We delayed the in-service date due to delays in the Site Evaluation Committee process.

imports come in at a variety of costs. When demand is low, such as at night and in the spring and fall, only the low-cost resources supply energy; when demand is the highest, such as on the hottest days of the year, even the highest cost generation may be needed. The highest-variable-cost generator needed sets the clearing price for all energy bought or sold in the market. As a result, prices are lower in low-demand periods and higher in high-demand periods; adding new low-variable-cost supply, such as Canadian hydro via new transmission, can avoid the need for the higher-variable-cost resources and thus lower the market clearing price. But usually energy prices change only slightly with additional supply. The biggest driver of energy prices is the price of natural gas, since natural gas-fired generation is the marginal, price-setting energy supply in the market approximately 75% of the time.[16] Variations in natural gas prices are responsible for much of the annual and seasonal variations in electricity prices. For example, natural gas prices are highest in winter, due to high non-electric demand for natural gas for space heating needs.

In 2015, the shares of annual supply in New England were as follows: natural gas-fired generation (41%); nuclear generation (25%); renewable generation, including wood, refuse, wind, and solar (8%); hydropower (6%); coal-fired generation (3%), oil-fired generation (2%), and net imports (17%).[17] In the future, the contribution of nuclear energy will be lower due to the planned retirement of Pilgrim Nuclear power plant, as will the contribution of coal due to the retirement of the Brayton Point and Bridgeport Harbor 3 coal-fired power plants. The share of renewable wind and solar generation will continue to increase, in part because of state Renewable Portfolio Standards (RPS) and state mandates to reduce carbon dioxide emissions from fossil fuel-fired generation capacity.

"Capacity" is a separate product provided by resources that can produce energy, but it is not the energy itself. Capacity is the capability to produce electricity at any time to meet expected or unexpected peak demands, such as energy needs on the hottest day of the year. Units of capacity are denoted in megawatts (MW) of capability. ISO-NE procures enough capacity on behalf of all customers to ensure the ability to meet expected and unexpected peak demands. The market price for capacity is as high as it needs to be to attract and retain enough investment to meet that standard. (Energy payments alone would not attract and retain enough capacity to meet that standard, since the energy prices cover fuel costs and only some of resources' capital costs and fixed costs.)

To procure capacity, ISO-NE administers annual three-year Forward Capacity Auctions (FCAs). The auctions are conducted each February for the delivery period starting 40 months later, from June through the following May. For example, the most recent FCA was conducted in February 2016 for delivery in June 2019 through May 2020. It was called "FCA 10" because it was the

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16 ISO New England (2016), Key Grid and Market Stats, https://www.iso-ne.com/about/key-stats, accessed December 14, 2016.

17 ISO New England (2016), Resource Mix, https://www.iso-ne.com/about/key-stats/resource-mix, accessed December 14, 2016.

tenth forward capacity auction ever held, and the next auction for 2020/2021 delivery will be called "FCA 11."

The capacity auctions clear the market at the intersection of its administratively-determined demand curve and the market supply curve. The demand curve is centered on a target quantity that ISO-NE determines for the entire system based on reliability criteria, a forecast of the system peak load, and a probabilistic analysis of the possibility of load being higher than expected and for generators becoming unavailable. The prices on the demand curve are calibrated (to an estimated cost of new capacity) so that the auction clears approximately the target quantity, or a little more if the market price is relatively low and a little less if it is relatively high. ISO-NE recently updated its demand curve shape from a downward sloping straight line used in recent auctions to a more left-shifted convex shape (i.e., bowed toward the origin), with prices falling more quickly immediately beyond the target quantity, then more gradually at higher reserve margins.[18] (ISO-NE will gradually transition from the old curve to the new one over the next three auctions—FCA11, 12, and 13.) ISO-NE's recent update also introduced local demand curves for import-constrained Southeast New England (SENE) and for export-constrained Northern New England (NNE), which includes New Hampshire. The local curve can decrease prices in Northern New England relative to the rest of the system when Northern capacity (including imported capacity) exceeds local needs and export limits, with larger surpluses producing larger price discounts. If NPT adds capacity to Northern New England, it would subject the zone to such discounts, as discussed in Section III.

The supply curve represents the offer prices and quantities of all participating suppliers, with offers arrayed in order of increasing price. Each offer price is the price at which a resource is willing to take on a capacity supply obligation. Taking on a capacity supply obligation involves several potentially costly commitments: developing or maintaining the resource so it will be online and able to produce; having to offer energy into ISO-NE's energy market; not having any capacity obligations to electricity systems outside of New England; and being exposed to high penalties if not performing under ISO-NE's newly implemented Performance Incentives mechanism.[19] When suppliers form their offers, they have to consider all of these factors against the economic consequences of not clearing as capacity. If a resource's alternative to clearing the market and taking on a capacity supply obligation is to retire, mothball, or not enter in the first place, it would not earn any net energy revenues; or if the alternative is to stay online without a capacity supply obligation, the resource could still earn net energy revenues but not face capacity performance penalties.

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18 Geissler/White Testimony, p. 126.

19 Federal Energy Regulatory Commission (FERC) (2014), Order on Tariff Filing and Instituting Section 206 Proceeding, Docket No. ER14-1050-000, *et al.* Issued May 30, 2014. 147 FERC ¶ 61,172. Available at: https://www.iso-ne.com/static-assets/documents/regulatory/ferc/orders/2014/may/er14_1050_000_5_30_14_pay_for_performance_order.pdf.

This combination of factors results in an upward-sloping supply curve with reliable existing and already-committed new resources generally at the bottom of the supply curve, since their capital costs are sunk and they face little exposure to performance penalties. Older resources that are less reliable and less efficient tend to offer at intermediate prices since they may incur more capacity performance penalties. And potential new entrants tend to be at the top of the curve since they would have to expend major capital to come online. Several such new plants have entered and cleared the market in the past few capacity auctions.

Other than imposing these obligations associated with capacity, ISO-NE applies several rules in advance of each auction to ensure that offered capacity can deliver reliably and that auction outcomes are competitive. Two such rules that are relevant to NPT are resource qualification and offer mitigation. Every resource must go through ISO-NE's resource qualification process to determine how many MW it can offer. Based on each resource's characteristics, ISO-NE determines its Summer Seasonal Claimed Capability and its Winter Seasonal Claimed Capability (each denoted in MW) and qualifies the resources at the minimum of the two.[20] For external resources such as those that NPT would enable, there is a special process: suppliers of external capacity can name a designated resource, which would be rated similarly to internal resources; or they can rely on their entire portfolio, but must demonstrate that they have enough surplus capacity beyond their own obligations to reliably deliver in both the summer and the winter.[21] For resources in Québec, winter surplus capacity is more limited since Québec's own demand peaks then. However, resources can qualify more capacity than the minimum of their Seasonal Claimed Capabilities if they bilaterally arrange with other complementary resources to qualify together as a single resource (and share the value if they clear).[22] Many generators in New England have greater winter capability than summer and so might be candidates for such arrangements. We are unaware of any such arrangements between NPT and other such generators.

Once capacity is qualified, its offer prices may be subject to review by ISO-NE's Internal Market Monitor. To prevent existing resources with large portfolios from economically withholding capacity to increase prices above competitive levels, the Internal Market Monitor reviews offers above a benchmark price called the Dynamic Delist Bid Threshold. More directly relevant to NPT, the Internal Market Monitor may also review new entrants' offers, including all offers by Elective Transmission Upgrades such as NPT. In this case, the Internal Market Monitor's goal is to prevent low offers supported by out-of-market payments from artificially suppressing capacity market prices. The Internal Market Monitor makes sure the offer is high enough to reflect the

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20 ISO New England (2016), Market Rule 1, Section III.13.1.1.2.5.1. Available at https://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1

21 ISO New England (2016), Market Rule 1, Section III.13.1.3.5. Available at https://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1

22 ISO New England (2016), Market Rule 1, Section III.13.1.5. Available at https://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1

full cost of providing capacity, including the capital and fixed costs of the enabling transmission (*e.g.*, NPT and accompanying new transmission on the Canadian side) and the capital and fixed costs of any new generation capacity built to support the export of qualified capacity to New England, minus any offsetting net energy revenues that are expected to help cover those costs (with capacity payments having to cover the rest). In that assessment, net energy revenues have to derive from "broadly available" market prices rather than special contractual out-of-market subsidies. If the Internal Market Monitor decides to mitigate the offer upward, the offer may not clear the capacity market or may clear with a reduced price impact if it clears as the marginal capacity.

To give a sense of the scale of the New England energy and capacity markets, the annual value of the energy market was about $6 billion in 2015 with an average energy price of $46/MWh on 127 million MWh of volume;[23] the annual value of the latest Forward Capacity Auction (FCA 10) was approximately $3 billion with a single clearing price of $7.03/kW-month on a volume of 35,567 MW.[24] New Hampshire accounts for approximately 10% of those amounts, corresponding to its share of the total New England load.

Customers do not participate directly in the wholesale markets. They use an intermediary called a retail electric provider. Retail electric providers compete to serve customers' generation needs and do not provide delivery services—even in cases where a customer chooses PSNH as its retail provider, which is a separate entity from PSNH the utility, who owns the wires and serves all customers in its territory as a regulated natural monopoly. Retail providers buy energy, capacity, and ancillary services from the wholesale market.[25] Typically, they contract with wholesale suppliers for energy and buy or sell imbalances on the ISO-administered spot market; they buy ancillary services on the spot market; and, for capacity, they are allocated a portion of the costs from the forward auctions in which ISO-NE procures capacity on behalf of all retail providers. Their portion is given by their customers' share of the system's forecast peak load.

When determining rates to offer their customers, retail providers generally pass through their wholesale costs, often along with a risk premium for providing a fixed price rate. As a result, reductions in wholesale costs caused by NPT would benefit customers through lower rates. Specifically, customers would see a lower rate on the generation component of their monthly electric bills, while the delivery services component of their bills would not be expected to

23 ISO New England (2016), Key Grid and Market Stats, https://www.iso-ne.com/about/key-stats, accessed December 14, 2016

24 ISO New England (2016), Markets, https://www.iso-ne.com/about/key-stats/markets, accessed December 14, 2016.

25 All retail electric providers must buy ancillary services from the wholesale electricity market. Ancillary services refer to several services that balance short-term differences between supply and demand due to fluctuations in load and intermittent generation and unexpected outages of generators and transmission facilities.

change.[26] For retail customers with PSNH, the generation rate (as of summer 2016) is about 11¢/kWh. The delivery services rate is about 7¢/kWh. Consequently, the total rate is about 18¢/kWh plus a customer charge of about $10 per month.[27] With typical residential consumption of 621 kWh per month, the average monthly retail bill is approximately $120.[28] This changes over time as consumption, fuel prices, capacity prices, and other factors vary.

II. Review of LEI Analysis

As a part of NPT's application to the New Hampshire Site Evaluation Committee, LEI filed direct testimony and a report summarizing its evaluation of the Project's economic benefits. LEI analyzed the extent to which NPT would reduce future wholesale energy and capacity market prices and translated the estimated regional energy and capacity savings into New Hampshire customer benefits. LEI estimated that NPT will result in wholesale price impacts of $81.0 to $82.5 million per year (in nominal terms) over the first 11 years of the line's in-service life, which we convert to customer savings of $75 to $76 million per year in constant 2020 dollars.[29] About 90% of LEI's estimated savings result from reductions in capacity market prices.[30]

LEI's estimated *capacity* market impacts are substantially higher than ours because they are based on outdated information and optimistic assumptions about several uncertain factors that tend to increase the benefits of NPT. We find that LEI's analysis of the *energy* market (as opposed to capacity market) and emissions appropriately captures the key issues and is not significantly outdated. We therefore adopted LEI's estimated energy market impacts with adjustments for differences in the amount of new natural gas-fired generation displaced by NPT. We also adopt LEI's GHG emissions estimates derived from the same energy market analysis for our Scenarios 1–3 (under our Scenario 4, NPT would not result in net reductions of GHG emissions). However,

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26 We understand that NPT would be paid for by its sponsors and/or shippers of power, not by all customers on the ISO-NE transmission system.

27 For residential customers, the generation portion of the bill is denoted in kWh even though it includes capacity and some other non-energy charges.

28 U.S. Energy Information Administration (2016), 2015 Average Monthly Bill—Residential, accessed December 2016. http://www.eia.gov/electricity/sales_revenue_price/pdf/table5_a.pdf.

29 Converting nominal dollars to constant 2020 dollars reduces the amounts by about 5%; to convert wholesale impacts to customer's savings, we also account for the price-insulating effect of long-term contracts, as LEI did when estimating customer savings. This further reduces the amounts by about 2.5%.

30 LEI reports the 10-year average of capacity market benefits for New Hampshire in Figure 1 of their report as $79.6–$80.1 million, but energy market and total wholesale market benefits are reported as an 11-year average. To put the values on a similar timescale, we calculated the capacity market benefits for New Hampshire over the same time frame as the energy market benefits to be $72 million. LEI Report, p. 14.

we provide alternative ways to assess the monetary value of GHG emissions reductions to New Hampshire.

In this section, we explain how our analysis differs from LEI. The full details of our analysis are provided in Sections III and IV.

A. Capacity Market Analysis

Our estimates of the Project's capacity market impacts (and associated customer benefits to New Hampshire) are substantially smaller than LEI's. Since capacity market benefits represent approximately 90% of the electricity market benefits LEI estimated, it is important to understand the reasons for these differences. We find that LEI's analysis of customer benefits is based on optimistic assumptions and outdated market conditions in ways that exaggerate likely capacity price impacts.

LEI does not address several key issues that we address in Section III, instead making the following optimistic assumptions:

- LEI assumes 1,000 MW of Hydro-Québec capacity via NPT will qualify in ISO-NE's capacity market;
- LEI assumes the ISO-NE Internal Market Monitor allows these resources to offer their capacity at low prices and clear the auction;
- LEI assumes NPT does not displace any competing clean energy projects that provide access to Canadian hydro or add renewable resources to the New England market;
- LEI assumes the supply curve is vertical over the range of prices projected in its analysis, which we find unlikely to be an accurate representation, as we discuss below and in Section III.A.2.[31] LEI's assumption maximizes the price impact of adding NPT's capacity.

The diagrams in Figure 1 below demonstrate the effect of NPT on clearing prices under different supply curve assumptions. The graph on the left assumes a vertical supply curve (representative of LEI's supply curve) and the one on the right assumes a more realistic sloped curve (representative of our supply curve). Both cases assume NPT capacity offers at a very low price, so the supply curve shifts rightward by 1,000 MW. Clearing prices decrease and cleared quantities increase as a result of NPT in both cases, but the effects are much greater when vertical supply curves are assumed (as LEI did). Modeling sloped supply curves accounts for the displacement of marginal capacity that would likely occur as a result of NPT entering the market, and this moderates the impact on prices.

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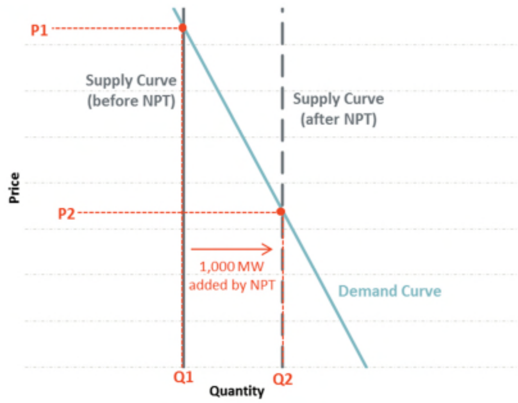
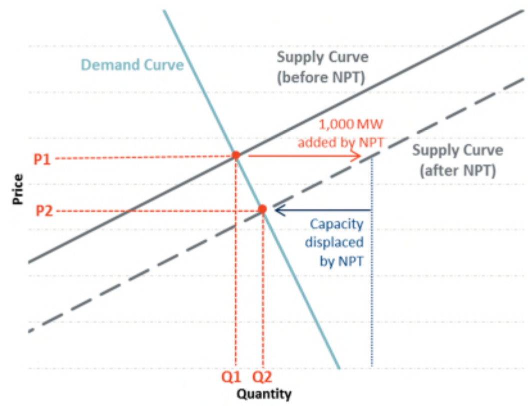
31 [redacted].

Figure 1: Stylized Capacity Market Supply Curves

(a) Vertical Supply Curve (b) Sloped Supply Curve





LEI completed its analysis in October 2015. Since then, the New England capacity market has undergone further evolution of its market design. Also, supply-demand fundamentals have shifted. As these developments had not fully transpired at the time LEI prepared its analysis, it is not surprising that they are absent from LEI's analysis. They do however have important implications for how the addition of NPT may impact capacity market clearing prices. The changes in market design and market conditions over the past year are expected to lead to lower capacity prices even without NPT, and less impact if NPT is added. The major changes and developments can be characterized as follows:

- ISO-NE updated the design of the Forward Capacity Market demand curve shape, such that capacity prices are lower at a given quantity (even without NPT).[32]
- Almost 900 MW of net additional supply cleared the market in the most recent auction (FCA 10): 1,459 MW new generation, 371 MW new demand resources, minus the net loss of 958 MW of existing capacity.[33]
- ISO-NE lowered its summer peak demand forecast.[34]
- Recent information on supply offer prices suggests that prices will remain within a tighter band with a flatter supply curve that stabilizes prices, thus limiting NPT's potential price impact (as we discuss further in Section III.A.2).
  - Several thousand MW of existing oil- and gas-fired generators have submitted offers at an average price of $5.50/kW-mo, some higher and some lower.[35] These offers

32 Geissler/White Testimony, p. 126.

33 ISO New England (2016), Markets: Results of the Annual Forward Capacity Auctions, https://www.iso-ne.com/about/key-stats/markets#fcaresults, accessed December 14, 2016.

34 ISO New England (2016), 2016–2025 Forecast Report for Capacity, Energy, Loads, and Transmission, 1.1 Summer Peak Capabilities and Load Forecast (MW), May 2, 2016. Available at: https://www.iso-ne.com/static-assets/documents/2016/05/2016_celt_report.xls.

- indicate the prices at which they will exit the market. The offer prices are higher than in past auctions because of newly-implemented performance penalties (which will be rising in the future).
  - New units have entered the market at lower prices than ISO-NE's estimated Net Cost of New Entry. Combined with other recent information we review in Section III.A.2 this suggests further low-cost entry in the future may limit prices even without NPT.

These issues affect projected capacity prices and hence NPT's capacity price impacts relative to LEI's price projections. Our projected prices therefore remain lower and within a narrower range than the LEI capacity prices, as shown in Figure 2 below. The price projection reflects our expectation of trends over time and serves as baseline for our analysis. It does not account for idiosyncratic factors that could cause actual individual auction prices to be higher or lower.

Compared to our Base Case prices, LEI's prices start higher in FCA 10 as they projected little entry or exit, but we have since learned that net supply increased almost 900 MW in FCA 10 (which was held in February 2016) and pushed the price lower.[36] Our Base Case prices then decrease slightly in the next auction (FCA 11) because of a projected decrease in demand that year (net of behind-the-meter photovoltaics and energy efficiency) and the beginning of the transition to the new demand curve shape. Thereafter, prices remain fairly flat for several years as factors that tighten the market, primarily modest load growth and retirements of existing capacity, offset factors that ease the market, primarily energy efficiency additions and the transition to ISO-NE's new demand curve shape. However, the main factor stabilizing prices throughout this period is the flatter supply curve due to the intermediate offer prices from marginal oil- and gas-fired capacity, as noted above. Factors that would tend to reduce market prices through FCA 12 are counter-balanced by the behavior of marginal oil- and gas-fired resources, which would likely not clear the market and then decide to retire, mothball, or operate without a capacity supply obligation; after the new demand curve is fully transitioned in FCA 13, projected net load growth would raise prices, but some of the price-sensitive capacity re-enters and tempers the escalation of prices. In FCA 16, marginal oil- and gas-fired capacity and other existing resources are likely to offer their capacity at higher bid prices as ISO-NE increases the penalty rate applied to capacity resources with poor performance, and this causes an uptick in market-clearing prices. The impact of the additional capacity via NPT is significant initially, particularly in NNE where NPT creates a local capacity surplus and suppresses local prices relative to the system. The local surplus and local price discount diminishes over time with assumed baseline retirements and load growth. However, NPT's overall effect on capacity prices

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Continued from previous page

35 McDonald/Laurita Testimony, pp. 680–681. Note that this document was available prior to the release of the LEI report.

36 ISO New England (2016), Markets: Results of the Annual Forward Capacity Auctions, https://www.iso-ne.com/about/key-stats/markets#fcaresults, accessed December 14, 2016.

is greatest in FCA 17 as Base Case prices rise to attract the new entry necessary to meet the system-wide capacity requirements, whereas NPT would delay this rise.[37]

Figure 2: Comparison of ISO-NE Forward Capacity Auction Prices (in NNE)

[redacted]

By contrast, LEI models prices to rise more quickly (from a higher starting point in FCA 10) and shows a greater impact of NPT on capacity prices because it used a higher and now-outdated forecast of load growth, because it did not (and could not at the time) account for the transition to the new demand curve shape, and because it modeled a vertical supply curve, as demonstrated in Figure 1 above. LEI's inelastic vertical supply curve makes prices rise more quickly due to load growth in the Base Case, and also fall more precipitously with the entry of NPT. [redacted].[38] Our prices rise only to $9/kW-mo, consistent with more recent data on the cost of new entry.

We estimate annual average capacity market savings for New Hampshire customers of only $22 million per year (Scenario 1) and $11 million per year (Scenario 2) versus the $67 million per year estimated by LEI.[39] The only way we find substantially higher capacity market impacts of

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37 These dynamics are described further in Section IV.A.

38 LEI Report, p. 50.

39 The LEI capacity market benefits for New Hampshire reported here appear lower than the $79.6 to $80.1 million annual capacity market impact presented in Figure 1 of their report because we calculated an 11-year average instead of a 10-year average (which reduces the amounts by 9%), converted their results from nominal dollars to 2020 dollars (which reduces the amounts by about 5%) and accounted for the price-insulating effect of long-term contracts, as LEI did when translating wholesale market savings to customer retail savings (which further reduces the amounts by about 2.5%). These adjustments are necessary to present our results and LEI's results in comparable terms.

NPT is under an alternative assumption that the net cost of new entry is $12/kW-mo instead of our $9/kW-mo based on the latest market information;[40] in that case, our capacity market benefits rise to $57 million per year. Other uncertain market variables we analyzed have a smaller effect, as shown in Section IV.A. However, in our Scenario 3, where NPT does not qualify or does not clear in the capacity market, but does provide energy, we estimate that capacity market payments will *increase* by $7 million per year. This is because reduced energy market revenues increase the price at which new natural gas-fired generation is willing to enter the capacity market. And we find no capacity market benefits in our Scenario 4, where NPT displaces other similar clean energy projects.

B. Energy Market Analysis

We find LEI's energy market modeling approach and results to be reasonable, so we largely adopt their results but make adjustments to account for differences in our capacity market analysis. Due to the differences discussed above, our Base Case capacity forecast remains in surplus longer, and new entry of natural gas-fired combined-cycle generators does not occur until 2026 (compared to 2024 in LEI's analysis).[41] Our longer period of surplus capacity prolongs NPT's energy market price reductions and the associated customer savings because NPT adds substantial amounts of low-cost energy without yet displacing the would-be entry of any combined-cycle capacity.[42] In addition, some of our scenarios count NPT capacity at less than the full potential (thus displacing less combined-cycle capacity) while delivering the same amount of energy, and this further extends the energy price impacts.[43]

Consequently, NPT's energy market benefits for New Hampshire customers increase from $7 million per year in LEI's lower natural gas price case to $8 to $12 million per year in our analysis of scenarios where NPT adds incremental clean energy supply in New England.[44] Energy market impacts are zero in our alternative Scenario 4, however, where NPT displaces the development of other clean energy projects.

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40 See Section III.A.2 for the basis for our best estimate of $9/kW-mo and for our choice of the range of potential values for purposes of our sensitivity analysis.

41 LEI Report, Figure 27, p. 56.

42 New combined-cycle generation provides low-cost energy most of the time and has a similar effect on energy market prices.

43 See Section IV.B for a more complete explanation of adjustments to LEI's energy price analysis.

44 The LEI energy market benefits for New Hampshire reported here appear lower than the $8.2 million annual energy market impact presented in Figure 1 of their report because we converted their results from nominal dollars to 2020 dollars (which reduces the amounts by about 5%) and accounted for the price-insulating effect of long-term contracts, as LEI did when translating wholesale market savings to customer retail savings (which further reduces the amounts by about 4%). These adjustments are necessary to present our results and LEI's results in comparable terms.

As LEI notes, this estimate is conservative because it does not account for extreme market conditions, such as especially high summer load and high winter natural gas prices, when energy prices can spike and NPT could provide additional benefits to customers.[45] LEI found that during five days in July 2013 when the system experienced especially high summer prices (up to $400/MWh), additional supply from NPT would have saved load [redacted] across New England.[46] Similarly, LEI finds that NPT would have reduced load payments by a similar amount [redacted] during a five day period similar to the 2013–2014 "polar vortex."[47] This estimate is before considering the uncertain benefit of NPT possibly reducing the need for natural gas-fired generation in New England and thereby mitigating spikes in natural gas prices during extreme cold conditions. This would further reduce electricity prices, since natural gas sets electricity prices most of the time, although neither we nor LEI's Report estimated the effect.[48]

C. Greenhouse Gas Emissions Analysis

We generally accept as reasonable LEI's estimate that NPT would reduce GHG emissions by approximately 3.3 million metric tons per year. We therefore adopt their estimate except in the scenario where NPT displaces other similar resources (Scenario 4). LEI's savings estimate assumes that new hydropower provides the incremental energy Hydro-Québec exports via NPT and that Hydro-Québec does not reduce its exports to other buyers if it increases exports to New England.[49] While LEI does not provide any evidence to support this assumption, we believe such an assumption to be generally plausible, given Québec's hydro potential (including new resources that could be developed), although GHG emissions reductions could indeed be smaller if hydro power flowing over NPT is rerouted from other customers and replaced by fossil-fired generation rather than hydro or renewable generation.

However, we explore in more detail than LEI how to value avoided GHG emissions from a New Hampshire perspective. LEI estimates a social cost of carbon (SCC) measure based on the SCC values developed by the Interagency Working Group on the Social Cost of Carbon for use by the

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45 LEI Report, pp. 59–64.

46 LEI Report, p. 61.

47 LEI Report, p. 64.

48 A potential issue not addressed by LEI (or us) is the impact of NPT on New England's natural gas prices during normal operating conditions as well as extreme cold conditions. In Scenarios 1 and 2 and possibly 3, where NPT reduces reliance on natural gas fired generation during the winter assuming all else is the same, natural gas prices could decrease. However, a detailed analysis of the impact of NPT on electricity prices through potentially lower gas prices is complex and requires making numerous assumptions about the impact of NPT on the gas supply. One reason not to assume a major impact of NPT on gas prices is a potential gas supply response to (or in the absence of) NPT. For example, reduced natural gas demand as a result of NPT could cause less incremental investment in new gas pipeline or storage capacity and/or less liquefied natural gas imports, which would at least partially offset any gas price reduction caused by NPT.

49 LEI Report, p. 67.

U.S. Environmental Protection Agency.[50] LEI does not use the annual SCC increases calculated by the Interagency Working Group, but rather constructs its own annual SCC measure by inflating the Interagency Working Group's 2020 value by a measure of energy inflation used in the U.S. Department of Energy's Annual Energy Outlook, subtracting an assumed RGGI allowance price from the SCC value, and then discounting the resulting values by a 7% discount rate.

While we agree that carbon abatement is important for society overall, LEI's methodology for valuing GHG emissions reductions is both oversimplified and fails to provide guidance as to how a global value could (or should) be translated into value for New Hampshire and its electricity consumers. The valuation of GHG benefits is a complex topic and we acknowledge that any quantification and allocation of assumed benefits to New Hampshire involves many assumptions and allows for the estimation of a large potential range of benefits, depending on those assumptions.

We conclude that if New Hampshire is committed to long-term reductions in GHG emissions as per its Climate Action Plan, then any NPT-based GHG reductions claimed by New Hampshire would provide value as an avoided cost of achieving similar reductions through other means. In that case, LEI's GHG benefits estimate is likely within the range (on a $/ton avoided basis) of the potentially avoided cost of alternative GHG emissions reductions. However, New Hampshire would be able to claim only a fraction of NPT's emissions reductions, perhaps corresponding to its contractual share of the line, not the entire volume of reductions as LEI assumed. Moreover, it is possible that the goals embedded in New Hampshire's Climate Action Plan are not meant to be legally enforceable targets and that New Hampshire's willingness to pay for emissions reductions could be lower.

III. The Future Wholesale Electricity Market with and without NPT

To analyze the impacts of NPT, we used an approach similar to LEI that models the future New England electricity market both with and without the project. We specifically modeled how resources are likely to enter or exit the market and how that would affect energy and capacity market prices and GHG emissions. From these results, we calculated the impact on New Hampshire customers and other stakeholders by finding the difference in prices and payments between the two cases.

The analysis is not straightforward, however, since the future is uncertain in ways that affect the value of NPT. Moreover, the sources of uncertainty are such that they do not easily lend themselves to a quantitative/probabilistic assessment that would allow collapsing various possible

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50 LEI Report, pp. 67–68.

future developments into one "expected" case.[51] One uncertain factor is the quantity and price of reliable capacity that Hydro-Québec would transmit via NPT. It is possible that ISO-NE would not qualify any capacity if Hydro-Québec cannot demonstrate that it has enough surplus capacity to reliably export power during the winter when its own system demand peaks. There is limited public information available and no information provided by the Applicants in this proceeding for us to determine how much capacity will qualify, if any. Furthermore, capacity that qualifies still may not clear the market. Clearing the capacity market depends on the price at which Hydro-Québec offers its capacity, which will be reviewed by ISO-NE's Internal Market Monitor. To prevent low offers supported by out-of-market payments from artificially suppressing market prices, the Internal Market Monitor can mitigate offers to ensure that they reflect the full cost of providing capacity. If the Internal Market Monitor decides to mitigate NPT's capacity offer, NPT may not clear the capacity market, which would result in NPT having no impact on capacity prices. Alternatively, NPT's upwards-mitigated capacity supply bid could set the market clearing price, which would be higher than what was assumed by LEI. Here too, there is insufficient information for us to determine whether and how much the Internal Market Monitor might mitigate NPT-related capacity offers.

Another crucial uncertainty is how competing suppliers respond to NPT. If NPT is competing in state-sponsored clean energy solicitations, such as the one expected next year in Massachusetts, it could displace another similar transmission project, such as the New England Clean Power Link running through Vermont, or other clean energy resources. NPT could also displace existing capacity resources, including generation, imports, or demand response resources whose continued provision of capacity is sensitive to reductions in market prices. For example, if NPT adds capacity and lowers the capacity price, an existing oil-fired steam plant may no longer clear the market; the plant's owner may decide to retire the plant, mothball the plant, or continue to operate the plant without taking on a capacity supply obligation and the costs and risks that entails. Similarly, NPT could displace a new capacity resource that would otherwise enter the market. We cannot perfectly predict how these market dynamics will work out, but estimating capacity displacement—and the prices at which displacement occurs—is important because it produces an offsetting effect on prices, reducing NPT's net impact.

To account for all of these uncertainties in our analysis of NPT, we developed several scenarios and sensitivity analyses. We focused primarily on capacity market dynamics and clean energy procurements because those determine supplier entry and exit decisions and, ultimately, customer costs and emissions. Furthermore, capacity market prices can be particularly sensitive to small changes in supply because the ISO-NE demand curve for capacity is very steep. Energy market prices are less sensitive because, even though the energy demand curve at any given time is even steeper, the New England supply curve for energy is extremely flat, so adding new supply or taking it away has a smaller effect on prices. For this reason, our scenarios are primarily

[51] In this case we use the term "expected" in the statistical sense, indicating the mean of a distribution of possible future outcomes.

driven by capacity market considerations and our analysis emphasizes capacity market impacts. The scenarios we constructed are as follows (presented in descending order of market price impact due to NPT):

- **Scenario 1: NPT expands the supply of clean energy into New England without displacing other similar projects, and it provides 1,000 MW of capacity.** This scenario most closely corresponds to LEI's project case. However, this scenario takes into account changes in capacity market design and changes in market information revealed since the submission of the LEI Report. It also assumes, unlike LEI, that the addition of NPT capacity would cause some more expensive capacity resources not to clear the market that would have cleared in the absence of NPT. As a result, the net increase in capacity is substantially less than NPT's 1,000 MW, and the capacity price impact is partially mitigated. Unlike Scenario 2 below, we assume that while this "displaced" capacity does not clear the market in the initial years following NPT entry, it does not permanently retire and could thus provide capacity in the future.
- **Scenario 2: Similar to Scenario 1, but NPT induces 500 MW of existing generation capacity to retire.** In this scenario, we assume 500 MW of existing capacity that would have cleared absent NPT, instead permanently retires when NPT enters due to the prospect of several years of reduced prices. We assume this 500 MW is spread throughout New England, with a third retiring in the Northern New England zone.
- **Scenario 3: NPT expands the supply of clean energy into New England without displacing other similar projects, but it does not provide any capacity.** This scenario reflects the possibility that Hydro-Québec imports via NPT may not qualify as a reliable capacity resource and/or may not clear the capacity market for the reasons noted above. Scenario 3 assumes the extreme case where zero NPT capacity qualifies and clears, recognizing that intermediate cases with partial qualification and clearing are also possible.
- **Scenario 4: NPT displaces competing clean energy projects, thus providing no more clean energy than if NPT were not constructed.** LEI and our Scenarios 1–3 assume NPT would expand the amount of clean energy in New England, reflecting the fact that NPT will access hydro resources in Québec that are not available now. In Scenario 4, we consider the possibility that NPT does not expand the amount of clean energy in New England, but rather that in the absence of NPT other similar clean energy resources would come online. Since several New England states are determined (and have laws on the books) to procure clean energy, NPT can be seen as one of several options to meet existing obligations. Absent NPT, one or several alternative options, such as the New England Clean Power Link through Vermont (which already has its siting permits), or incremental wind and photovoltaic resources in New England, might be developed instead. Scenario 4 therefore compares a world with NPT to a world in which a similar competing project is built instead. This scenario allows us to consider the possibility that granting NPT a permit may only shift the delivery of future clean energy from some combination of regional renewable generation and hydro imports delivered over another line to the same amount of clean energy being delivered over this line through New Hampshire, and to

ask what the relative electricity market-related benefits to New Hampshire would be in such a case.

In the following sections, we explain how we developed our Base Case, followed by each of the Project Cases that reflect the four scenarios discussed above. For the Base Case, we present our assumptions about supply and demand and how we model the capacity auctions to project prices and resources operating in New England through 2031. For each NPT scenario, we apply the same base assumptions and model mechanics to assess how adding NPT would affect other resources' entry and exit decisions.

A. Base Case (without Northern Pass)

Our Base Case is constructed from public information about today's market conditions, widely-accepted demand forecasts, and reasonable assumptions about future generation retirements and new resources added to meet demand growth and established clean energy goals. We model ISO-NE's Forward Capacity Market (FCM) to determine when existing supply might exit and when new supply might enter, and the resulting prices. The sections below explain the supply and demand curves and the market clearing we modeled.

1. Demand Assumptions

In the forward capacity auctions, the demand curve is determined administratively by ISO-NE. ISO-NE recently revised how it constructs the demand curve from a downward-sloping straight line to a Marginal Reliability Impact (MRI) curve that is convex to the origin and generally left-shifted (lower price at the same capacity) compared to the linear curve used previously.[52] A transition period over the next three capacity auctions (FCA 11 to FCA 13) will combine elements of the straight line curve (at prices below $7/kW-mo) and the new MRI curve (at prices above $7/kW-mo) with a horizontal portion at $7/kW-mo connecting the two sections.[53] To construct the future demand curves, we use ISO-NE's MRI analysis for setting the FCA 11 transition curves and adjust the curves each year due to load growth and projected Net Cost of New Entry (Net CONE).[54]

The demand curve quantities are centered on ISO-NE's reliability requirement for capacity, known as the Net Installed Capacity Requirement (NICR). For FCA 11 (delivery in June 2020 through May 2021), ISO-NE established an NICR of 34,075 MW, which results in a 15% reserve

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52 Geissler/White Testimony, p. 126.

53 Geissler/White Testimony, pp. 152–156.

54 The sloped section gradually moves to the left at fixed increments defined in ISO-NE's testimony and the MRI section shifts to the right with load growth. If load growth results in the MRI section moving to the right of the linear curve, the transition period ends and the full MRI curve is used. We find that the transition curves will be employed for FCA 11 and FCA 12 with the MRI curve used starting in FCA 13.

margin above the 29,600 MW projected summer peak load for 2020, net of behind-the-meter solar photovoltaics.[55] For subsequent years, we estimate the NICR based on the ISO-NE's peak load forecast, assuming the same reserve margin as in FCA 11.[56] The resulting NICR grows by an average of 320 MW per year from 34,075 MW in 2020 (FCA 11) to 37,280 MW in 2030 (FCA 21).

ISO-NE sets its demand curve prices to procure the target quantity by setting the demand price at the estimated Net CONE where the demand curve quantity equals NICR—with higher prices at quantities below that point and lower prices above, corresponding to the pre-defined demand curve shape. This recognizes the declining marginal reliability value of capacity and allows the auction to procure somewhat less capacity when prices are high and more when prices are low. ISO-NE has set Net CONE for FCA 11 at $11.64/kW-mo, and it proposes to reduce Net CONE for FCA 12 to $8.04/kW-mo based on its most recent study of the cost of entry.[57] However, we assume (as explained in more detail below) that Net CONE settles at $9/kW-mo (in 2020 dollars) in FCA 12 and thereafter, only rising with inflation.

Our adoption of ISO-NE's new demand curve shape (including the transition period) and our forecast of NICR and Net CONE result in the family of demand curves shown in Figure 3 below.

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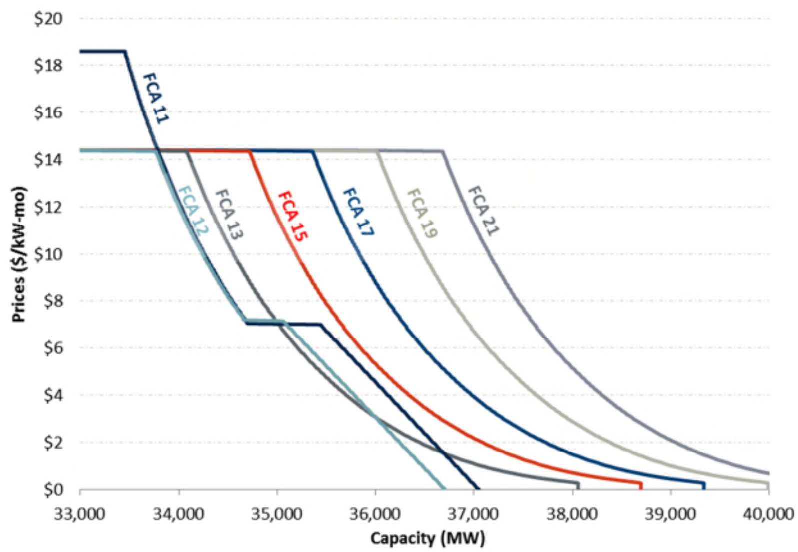
55 ISO-NE/NEPOOL (2016b), Letter with attachments to The Honorable Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, Electronic filing: ISO New England Inc., Docket No. ER17-___-000, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2020–2021 Capacity Commitment Period, November 8, 2016. https://www.iso-ne.com/static-assets/documents/2016/11/icr_filing_for_2020-2021_ccp.pdf

56 For ISO-NE's peak load forecast, see ISO-NE (2016), 2016–2025 Forecast Report for Capacity, Energy, Loads, and Transmission, 1.1 Summer Peak Capabilities and Load Forecast (MW), May 2, 2016. Available at: https://www.iso-ne.com/static-assets/documents/2016/05/2016_celt_report.xls. We use the demand forecast with reduction from behind-the-meter solar photovoltaics (BTM PV).

57 For FCA 11 Net CONE, see: ISO New England (2016), Forward Capacity Market Parameters, https://www.iso-ne.com/static-assets/documents/2015/09/FCA_Parameters_Final_Table.xlsx, April 13, 2016. For proposed FCA 12 Net CONE, see: Concentric Energy Advisors (2016), ISO-NE CONE and ORTP Analysis, Redlined Draft Report, December 2, 2016. Available at: https://www.iso-ne.com/static-assets/documents/2016/11/a4_cea_cone_ortp_report_redline.docx

Figure 3: Future System-Wide Capacity Demand Curves



In addition to the system-wide demand curves, we modeled ISO-NE's new local demand curve in the export-constrained Northern New England (NNE) zone.[58] The NNE demand curve accounts for the limited transmission capability for exporting surplus local capacity to the load centers in Massachusetts, Connecticut, and Rhode Island.[59] When exports would otherwise be high compared to the transmission limit, the NNE demand curve will reduce the quantity and price cleared in NNE. Figure 4 below shows the projected future NNE demand curve for several auctions. The lower price would reflect the reduced marginal reliability value of an additional unit of capacity in NNE compared to the rest of the system. The capacity price in NNE is particularly relevant to this case since both the terminus of NPT and New Hampshire customers reside in it. If NPT provides 1,000 MW of capacity, it could depress the NNE price more than the system price.

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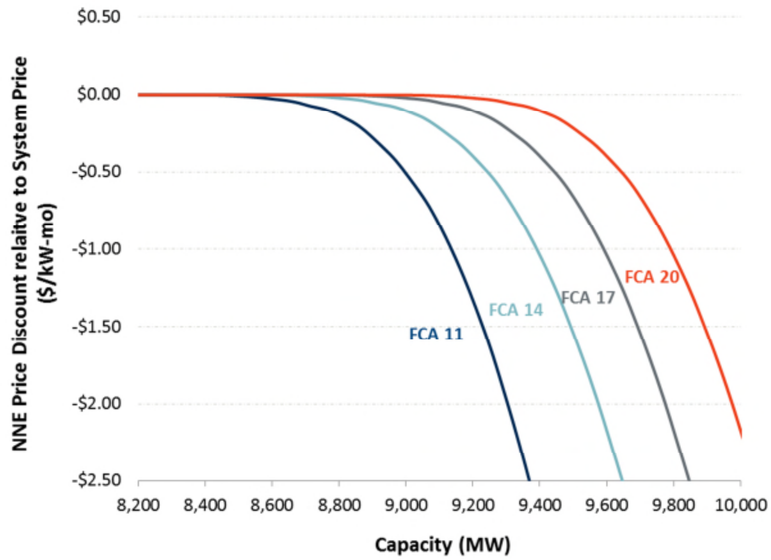
58 The NNE capacity zone includes capacity located in Vermont, New Hampshire, and Maine.

59 For the NNE capacity zone, load growth in New Hampshire, Vermont, and Maine increases the Maximum Capacity Limit (MCL) by an average of 65 MW per year from 8,980 MW in 2020 to 9,650 MW in 2030. ISO New England (2016), 2016–2025 Forecast Report for Capacity, Energy, Loads, and Transmission, 1.1 Summer Peak Capabilities and Load Forecast (MW), May 2, 2016. Available at: https://www.iso-ne.com/static-assets/documents/2016/05/2016_celt_report.xls. We do not model the import-constrained capacity zone in Southeast New England (SENE) due to the substantial entry in this region over the last several auctions.

Figure 4: Future NNE Capacity Demand Curves



2. Supply Assumptions

The capacity market supply curve is important because, along with the demand curve, it determines prices and price impacts when new supply is introduced by NPT. We find that the supply curve has become flatter over time (*i.e.*, more elastic; increasing more gradually), which will limit the price impact of NPT.

a. How the Supply Curve has Become Flatter

Supply curves represent the collection of all suppliers' individual resource-based offers to take on capacity supply obligations with the various offers arrayed in order of increasing offer price. Supply curves are upward-sloping, with the lower end generally composed of existing resources whose capital investments are already sunk, and the higher end composed of new resources that would have to expend large amounts of capital to enter the market. (See Section I.B for further discussion of supply curves.)

The shape of the capacity supply curve in New England has flattened since ISO-NE introduced its Performance Incentive penalty mechanism starting with FCA 9 for the 2018/19 delivery year. Prior to Performance Incentives, existing resources could remain financially viable even at very low capacity prices as long as they covered their relatively low going-forward fixed costs. With Performance Incentives, taking on a capacity supply obligation exposes resources to penalties for under-performance during system shortage conditions. Exposure to penalties increases the cost for unreliable resources taking on a capacity supply obligation. This means that older, less reliable resources, such as oil-fired steam generators, will require a higher capacity price to take on such risks, leading to higher offer prices at the lower end of the supply curve. It does not substantially elevate the offer prices at the higher end of the curve corresponding to potential new entrants with good expected performance; instead, it is more likely to lower those offer prices as new plants tend to over-perform and thus earn incentive payments instead of penalties. As a result, the supply curve has become flatter.

ISO-NE's Internal Market Monitor has acknowledged the effect of Performance Incentives on offers from existing resources by allowing them to offer their capacity at higher prices that account for both their costs and their risk of penalties. Before Performance Incentives, the Internal Market Monitor would review any offer above $1/kW-mo for being uncompetitively high, and it could mitigate the offer downward to prevent the exercise of market power. With Performance Incentives in effect, the Internal Market Monitor will no longer review offers unless they exceed the Dynamic Delist Bid Threshold of $5.50/kW-mo.[60] Furthermore, staff members at ISO-NE have made the same observations we did about the overall supply curve consequently becoming more elastic.[61]

The effect of this flatter supply curve is to make the resources in the market more responsive to changes in prices driven by shifts in supply, such as the addition of NPT; and those responses reduce the impact NPT has on capacity prices compared to the impact it might have had prior to the adoption of Performance Incentives. If prices become low, some existing resources may temporarily exit or operate without a capacity supply obligation, or they may permanently exit by retiring. Their willingness to exit at lower prices limits the net impact on prices from another resource's entrance. Conversely, if prices subsequently rise, some recently-exited capacity resources may re-enter or new resources may enter the market. In both directions, having a flatter more elastic supply curve has the effect of making capacity prices less responsive to changes in supply.

b. Construction of Supply Curves for Our Base Case

Unfortunately, ISO-NE does not make the auction supply curves publicly available, but various sources provide enough information for us to derive a reasonable approximation. We start with a core supply shape based on data made publicly available in PJM and used by The Brattle Group

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60 For existing resource offers above the Dynamic Delist Bid Threshold, the Internal Market Monitor analyzes whether the offer appears competitive. The Internal Market Monitor calculates a competitive benchmark for each review resource, given by the net avoidable going forward costs (***i.e.***, avoidable fixed costs minus expected net revenues from the energy and ancillary services markets) plus expected performance penalties and risks. If the Internal Market Monitor determines that an offer is priced higher than the competitive level, the Internal Market Monitor will mitigate the offer price down to that level.

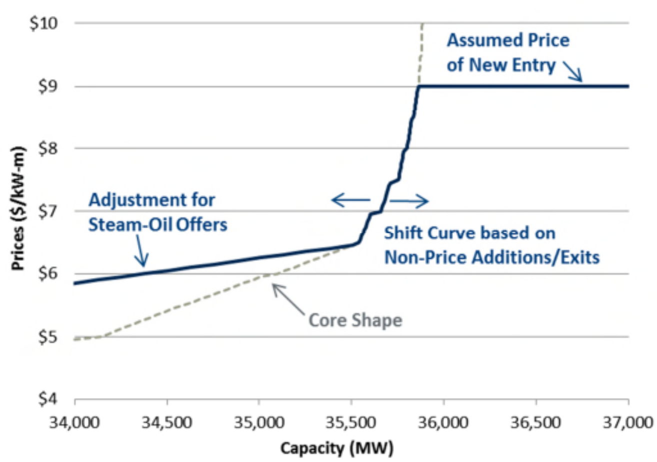
61 "First, one set of models simply evaluate the performance of the curves at specific price levels. We refer to such models as 'forward looking' as they are also consistent with equilibrium bidding behavior under the ISO's two settlement capacity market design (also known as Pay for Performance). Under that design, the capacity supply curves are expected to be far more price-elastic (that is, flatter) in the vicinity of where the market clears than has been the case historically, where supply bids primarily reflected a resource's avoidable costs." Geissler/White Testimony, pp. 120–121.

in past analyses of the ISO-NE forward capacity market.[62] We calibrate the core supply shape to the results of FCA 10 (held in February 2016) by adjusting the curve left/right until it passes through the clearing point from that auction, with a price of \$7.03/kW-mo at a quantity of 35,567 MW.[63] Similarly, in Northern New England, we assume the same shape as the system supply curve, with a \$7.03 price occurring at a quantity of 8,521 MW.[64]

We then modify the core shape to account for Performance Incentives and other market conditions in New England: (1) we replace the lower end of the supply curve with a sloped section that accounts for offers from marginal oil- and gas-fired generators that are most affected by Performance Incentives and likely to be priced around the Dynamic Delist Bid Threshold (DDBT); (2) on the right part of the curve, we apply a horizontal shelf at the price necessary to attract new generation when needed, given by the estimated Net Cost of New Entry (Net CONE). Finally, we shift the curve to the left or right each year based on non-price-driven additions (such as energy efficiency and new renewable resources) and retirements that are likely to occur in both the case with and without NPT. We provide more detail on each assumption below.

Based on these adjustments, Figure 5 shows our modeled FCA 11 base case supply curve.

Figure 5: Representative Supply Curve



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62 The core supply shape is available in the Markets Committee meeting materials, see: ISO New England, Markets Committee, https://iso-ne.com/committees/markets/markets-committee.

63 ISO New England (2016), Markets: Results of the Annual Forward Capacity Auctions, https://www.iso-ne.com/about/key-stats/markets#fcaresults, accessed December 14, 2016.

64 In FCA 10, 8,521 MW of resources located in NNE or Canadian imports that interconnect in NNE cleared the market. ISO New England (2016), 2019–2020 Forward Capacity Auction Obligations, April 13, 2016. See https://www.iso-ne.com/static-assets/documents/2016/02/fca_10_obligations.xlsx

We developed the **lower end of the supply curve** based on recent testimony by ISO-NE's Internal Market Monitor on offers from marginal oil- and gas-fired capacity and its calculation of the DDBT.[65] In setting the DDBT for FCA 11, the Internal Market Monitor reviewed offers from 5,100 MW of oil and dual fuel fossil steam and combustion turbine generators (which we refer to as "marginal oil- and gas-fired capacity") and found the average offer to be $5.50/kW-mo.[66] Based on this analysis, we assume there is 5,000 MW of capacity that will offer into future FCAs at prices near the DDBT, with some above and some below. The Internal Market Monitor did not provide any information on the range of offers that went into calculating the average. We make a simplifying assumption that the 5,000 MW will be equally spread across a range within plus/minus $1/kW-mo of the DDBT value.[67] We find that our results are not very sensitive to alternative assumptions of plus/minus $0.5/kW-mo or plus/minus $2/kW-mo in Section IV.A below.

The DDBT and the capacity offer prices of marginal oil- and gas-fired generators are expected to rise in future auctions as ISO-NE increases its performance penalty rate from $2,000/MWh in FCA 11 to $3,500/MWh for FCA 12 through FCA 15 and then $5,455/MWh for FCA 16 and thereafter.[68] In addition, as the current capacity excess dwindles due to exit and load growth, tighter supply conditions will likely increase the number of scarcity hours each year when performance penalties apply.[69] Based on recent ISO-NE analysis of forecasted scarcity hours, we assume that scarcity hours will increase from 8.0 hours in 2020/2021 to 11.3 hours in 2025/2026 and later years as excess capacity exits the market.[70] As a consequence, we project the average offers of marginal oil- and gas-fired generators to rise to about $6.00/kW-mo for FCA 12 through FCA 15, and about $7.25/kW-mo for FCA 16 to FCA 21.[71] Over time the rising offers will

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65 McDonald/Laurita Testimony.

66 McDonald/Laurita Testimony, pp. 11–12.

67 The resulting slope of the section of the offer curve encompassing marginal oil- and gas-fired capacity is $0.0004/MW ($2/kW-mo divided by 5,000 MW), which is similar to the slope at the low end of the range of the core supply curve shape noted above.

68 Federal Energy Regulatory Commission (FERC) (2014), Order on Tariff Filing and Instituting Section 206 Proceeding, Docket No. ER14-1050-000, *et al.* Issued May 30, 2014. 147 FERC ¶ 61,172. Available at: https://www.iso-ne.com/static-assets/documents/regulatory/ferc/orders/2014/may/er14_1050_000_5_30_14_pay_for_performance_order.pdf

69 Scarcity hours are the hours in which there are insufficient reserves to meet reserve requirements due to unexpected market conditions, such as higher than expected demand, a sudden outage of a generator or a transmission facility, or a loss in fuel supply, such as a natural gas pipeline.

70 Fei Zeng (2016), Estimated Hours of System Operating Reserve Deficiency—Final Results: Capacity Commitment Period 2020–2021, October 13, 2016, p. 8. Available at: https://www.iso-ne.com/static-assets/documents/2016/10/PSPC10132016_A2_2020-21_Reserve_Deficiencies_Hours_Final.pdf

71 We calculate the future DDBT by assuming the average net going-forward costs for marginal oil- and gas-fired capacity remains constant in real terms at $3.70/kW-mo, as estimated by ISO-NE

Continued on next page

further flatten the supply curve and increase the responsiveness of existing supply to changes in price, and this will reduce any price impact of NPT. We use sensitivity analysis to test the uncertainty concerning the future level of offers from marginal oil- and gas-fired generators.[72]

The **upper end of the supply curve** is composed of offers by potential new natural gas-fired generation. Their offers reflect the levelized capital cost plus annual fixed costs minus expected net revenues from the energy and ancillary services markets. The cost of new entry is uncertain, but it has been consistently below the Net Cost of New Entry that ISO-NE and PJM estimated for setting their demand curves. We estimate a central value of $9/kW-mo (in 2020 dollars) reflecting entry from new natural gas-fired combined-cycle plants[73] and test a range of $7 to $12/kW-mo for our sensitivity analyses. Our assumed range of the cost of new entry is based on the following data points:

- ISO-NE's most recent Net CONE study estimated that new natural gas-fired frame-type simple-cycle combustion turbines (CTs) are likely to enter the market at $8.04/kW-mo (in 2021 dollars) and combined-cycle plants (CCs) at $10.00/kW-mo.[74] Based on this analysis, ISO-NE is recommending that the Net CONE value for FCA 12 be set at $8.04/kW-mo,[75] which is 30% lower than the FCA 11 Net CONE of $11.64/kW-mo.[76] The decrease in the Net CONE value is primarily due to the choice of a frame-type CT as

Continued from previous page

(McDonald/Laurita Testimony, p. 11). We estimate future capacity performance penalties and risk premia based on data specific to existing oil/gas steam units and at-risk combustion turbines in New England using the approach outlined by ISO-NE for each risk premium component. For an explanation of the ISO-NE approach to calculating the risk premium, see: ISO New England (2014), Internal Market Monitor Review of De-list Bids for the Ninth Forward Capacity Auction: A Methodology Document, September 26, 2014.

72 We could have assumed the baseline retirements of 200 MW per year would reduce the remaining capacity that offers in this range, but did not because there would likely be an offsetting increase over the next ten years, with other existing units aging and beginning to offer similarly to the 5,100 MW the Internal Market Monitor identified in its calculation of the DDBT. In any case, our sensitivity analyses show that adjusting this assumption would not have a major effect on our results.

73 LEI makes a similar assumption that new entry is likely to be from natural gas-fired combined-cycle generation capacity, albeit at higher prices. LEI Report, pp. 50–51.

74 Concentric Energy Advisors (2016), ISO-NE CONE and ORTP Analysis, Redlined Draft Report, December 2, 2016. Available at https://www.iso-ne.com/static-assets/documents/2016/11/a4_cea_cone_ortp_report_redline.docx

75 ISO New England (2016), Markets Committee 2016-12-06 Meeting Materials, a_iso_cone_ortp_mr1_redlines.docx, December 7, 2016. Available at: https://iso-ne.com/static-assets/documents/2016/12/12_6_mc_mtg_materials_consolidated.zip

76 ISO New England (2016), Forward Capacity Market Parameters, April 13, 2016. Available at: https://www.iso-ne.com/static-assets/documents/2015/09/FCA_Parameters_Final_Table.xlsx.

the reference technology instead of a CC.[77] In addition, both the CT and CC Net CONE values are lower than previously estimated due to an increase in the estimated net revenues from energy and ancillary services.[78]

- Six new natural gas-fired generators cleared in the past two Forward Capacity Auctions at lower prices than ISO-NE's prior Net CONE estimates. Table 1 below shows that a CC and a CT cleared in FCA 9 at $9.55/kW-mo and, most recently, two CCs and a CT cleared in FCA 10 at $7.03/kW-mo. An aeroderivative combustion turbine cleared FCA 9 at the clearing price for the import-constrained Southeast Massachusetts/Rhode Island (SEMA/RI) region of $17.33/kW-mo, but that was a more expensive generator that was able to get permitted and developed quickly enough to take advantage of temporary high prices in SEMA/RI. Several of these units are being constructed at brownfield sites with existing facilities, possibly offering modest cost advantages (Wallingford, West Medway, Bridgeport Harbor, Canal) that may also be available to future projects at other brownfield sites. The Towantic Energy Center and Clear River Energy Center are both proposed to be built at greenfield sites. We understand that these units received special tax incentives through bonus depreciation that we estimate to be worth $0.7/kW-mo, but future entrants will not be able to receive these incentives as they phase out in 2020.[79]

Table 1: New Natural Gas-Fired Generators Cleared in Recent Forward Capacity Auctions

Unit	Unit Type	Capacity (MW)	State	FCA Cleared	Clearing Price
Towantic Energy Center	Gas CC	725 MW	CT	FCA 9	$9.55/kW-mo
Wallingford Energy GT 6 and 7	Gas CT	90 MW	CT	FCA 9	$9.55/kW-mo
West Medway II	Gas CT	195 MW	MA	FCA 9	$17.73/kW-mo
Bridgeport Harbor Station	Gas CC	484 MW	CT	FCA 10	$7.03/kW-mo
Canal 3	Gas CT	333 MW	MA	FCA 10	$7.03/kW-mo
Clear River Energy Center	Gas CC	485 MW	RI	FCA 10	$7.03/kW-mo

Source: ISO New England (2015), Forward Capacity Auction 2018–2019 Obligations, February 25, 2015; ISO New England (2016), 2019–2020 Forward Capacity Auction Obligations, April 13, 2016.

- When ISO-NE analyzed the likely performance of its recently-revised demand curve shape, it assumed perfectly elastic (*i.e.*, flat) supply curves priced at Net CONE. Their base case assumed the FCA 10 Net CONE of $10.81/kW-mo, but they also conducted

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77 ISO-NE previously chose the natural gas-fired CC and not the frame-type CT as the reference technology due to the lack of development in New England of frame-type CTs. However, the Canal 3 unit that cleared in FCA 10 is a frame-type CT demonstrating that this technology is a permitted and cost-effective technology in New England.

78 The Net CONE analysis prior to FCA 9 found the frame-type CT Net CONE was $8.47/kW-mo and the CC was $11.08/kW-mo. The estimated net energy and ancillary services revenues increased from $1.7/kW-mo to $3.3/kW-mo for the frame-type CT and from $3.3/kW-mo to $5.6/kW-mo for the CC.

79 Bonus depreciation of 30% is currently allowed for facilities that enter into service in 2019. Starting in 2020, the bonus depreciation will no longer be available.

sensitivity analyses at $7.00/kW-mo, $9.55/kW-mo, and $12.00/kW-mo to account for the future potential range of Net CONE values.[80] We adopt this same range for our sensitivity analysis, as presented in Section IV.A.

- New natural gas-fired generation capacity has entered at low prices in other regions, demonstrating a downward national trend. PJM has recently cleared over 5,000 MW of new natural gas-fired generation at prices in the range of $3 to $6/kW-mo. While capacity clearing prices in PJM tend to be lower than New England due to greater revenues from energy and ancillary services in PJM, the clearing prices have been below PJM's own Net CONE estimates. Similarly in Texas, Exelon is developing two CCs with a reported construction cost of $700/kW (compared to the estimated capital costs for a new CC in ISO-NE of $1,124/kW in the recent Net CONE analysis, and regional differences are not enough to explain the discrepancy).[81]

c. *Shifts in Supply over Time*

Once we have drawn the supply curves, we shift them left or right (slightly left on net over the time frame considered) to account for capacity additions and retirements that we assume to occur over time irrespective of clearing prices. These include annual growth of energy efficiency resources and the addition of new renewable generation to meet Renewable Portfolio Standards (RPS) on the positive side and assumed non-price retirements of old plants on the negative side.

Energy Efficiency. Although energy efficiency physically reduces demand, ISO-NE treats it on the supply side of its capacity market. We adopt ISO-NE's treatment and its projections of future energy efficiency capacity additions: 2,200 MW of new energy efficiency capacity is added between FCA 11 and FCA 21 in ISO-NE with 330 MW installed in NNE.[82]

New Renewable Generation. The New England states are procuring increasing amounts of renewable resources to meet growing Renewable Portfolio Standard (RPS) mandates. RPS-driven demand for Class I renewable generation will increase by 10,800 GWh between 2015 and

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80 Geissler/White Testimony, p. 134.

81 A utilities analyst from UBS recently noted, "Even when embedding a lower $700/kW construction cost (equal to the rock-bottom new construction prices EXC was able to negotiate with GE for its new development last year), equity IRRs are just ~10%." UBS (2015), "US Electric Utilities & IPPs: ERCOT: A Solar Eclipse?," Global Research, March 18, 2015.

82 ISO New England (2016), 2016–2025 Forecast Report for Capacity, Energy, Loads, and Transmission, 5.2 Summary of Demand Resource Capacity (MW) Used in System Planning Studies, May 2, 2016. Available at: https://www.iso-ne.com/static-assets/documents/2016/05/2016_celt_report.xls The ISO-NE report includes projections through 2025. We assume in years after 2025 that energy efficiency will continue to be added at the 2025 rate (179 MW per year).

2030.[83] We assume future incremental renewable generation to be provided by a combination of resources: 1,200 MW of onshore wind capacity and 600 MW of utility-scale solar PV capacity are added between 2017 and 2021; 800 MW of offshore wind capacity are added in 2022; and approximately 2,000 MW of distributed solar PV are added between 2016 and 2030.[84] ISO-NE accounts for the fact that these resources generate only intermittently by discounting their capacity for capacity market purposes (16% credit for solar PV, 30% for onshore and offshore wind).[85] Based on these assumptions, incremental onshore wind and utility-scale solar PV capacity will add 152 MW of capacity value in FCA 11 and FCA 12 combined, and offshore wind will add 240 MW of capacity value in FCA 13.[86] We assume the onshore wind capacity is added in the NNE capacity zone and the rest of renewable capacity is built in southern New England.[87]

Non-Price Retirements. Finally, some existing resources are likely to retire either based on reductions in clearing prices or irrespective of prices if they would have to incur major capital expenses to continue operating. We model the price-sensitive exit of existing resources as part of our market clearing (as discussed above), but we model baseline, non-price-sensitive retirements as a leftward shift in our supply curve. The price and timing of retirements is challenging to predict as evidenced by several recent unexpected retirement announcements.[88] We estimate future non-price retirements based on trends. Table 2 below shows that between 2013 and 2021 4,500 MW of existing capacity retired or announced retirement in New England. These

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83 ISO New England (2016), ISO New England Renewable Portfolio Standards Spreadsheet, May 2016. Available at: http://www.iso-ne.com/static-assets/documents/2016/05/a3_2016_economic_study_scope_of_work_rps_spreadsheet.xlsx

84 We based the distributed solar capacity on the ISO-NE RPS Forecast through 2025 and assume distributed solar capacity is added at increasing rates after 2025 based on the increase from 2024 to 2025. We assume that the Massachusetts procurement of offshore wind results in half of the total procurement allowed through 2030 (1,600 MW). We limit the procurement to half to account for the potential that the offshore wind costs will not decline as projected. We then add sufficient onshore wind and solar to meet the cumulative REC demand between 2015 and 2030.

85 The capacity credit accounts for the likely output of the renewable resources during scarcity hours. The value tends to be similar to the capacity factor (but not the same). For onshore wind and solar, see: Concentric Energy Advisors (2016), *ISO-NE CONE and ORTP Analysis*, Draft Report, October 28, 2016. Available at: https://iso-ne.com/static-assets/documents/2016/10/a_cea__draft_report_iso_ne_cone_ortp_analysis.docx.
For offshore wind, see: ISO New England (2016), 2015 Economic Study Evaluation of Offshore Wind Deployment, September 2, 2016, p. 7. Available at: https://iso-ne.com/static-assets/documents/2016/09/2015_economic_study_offshore_wind_development_final.docx

86 Our testing of different outlooks for the RPS resulted in trivial impacts on the outcomes of the capacity markets.

87 The distributed solar PV capacity (also known as behind-the-meter solar PV) is netted out of the peak demand and thus is not included on the supply side in our capacity market analysis.

88 Neither we nor other market analysts of whom we are aware anticipated most of the recent retirements, and those retirements did not occur at particularly low prices.

retirements include 1,800 MW of coal-fired generation, 1,300 MW of nuclear plants, and 1,400 MW from steam oil/gas-fired units and oil-fired combustion turbines (CTs).

Table 2: Recent and Planned Generation Retirements

Plant Name	State	Fuel Type	Retirement Year	Summer Capacity (MW)
Norwalk Harbor	CT	Oil	2013	342
Millinocket	ME	Oil	2014	70
Mount Tom	MA	Coal	2014	143
Bridgeport Harbor 2	CT	Oil	2014	131
Salem Harbor 3	MA	Coal	2014	150
Salem Harbor 4	MA	Oil	2014	437
Vermont Yankee	VT	Nuclear	2014	604
Lowell Cogeneration	MA	Gas	2017	28
Brayton Point 1-3	MA	Coal	2017	1,090
Brayton Point 4	MA	Oil	2017	435
Pilgrim	MA	Nuclear	2019	677
Bridgeport Harbor 3	CT	Coal	2021	383
Total Coal				1,766
Total Nuclear				1,281
Total Oil/Gas				1,443
Total Retirements				**4,490**

Sources: Velocity Suite, ABB Inc. Excludes units with nameplate capacity less than 25 MW. ISO New England (2016), Markets: Results of the Annual Forward Capacity Auctions, https://www.iso-ne.com/about/key-stats/markets#fcaresults, accessed December 14, 2016.

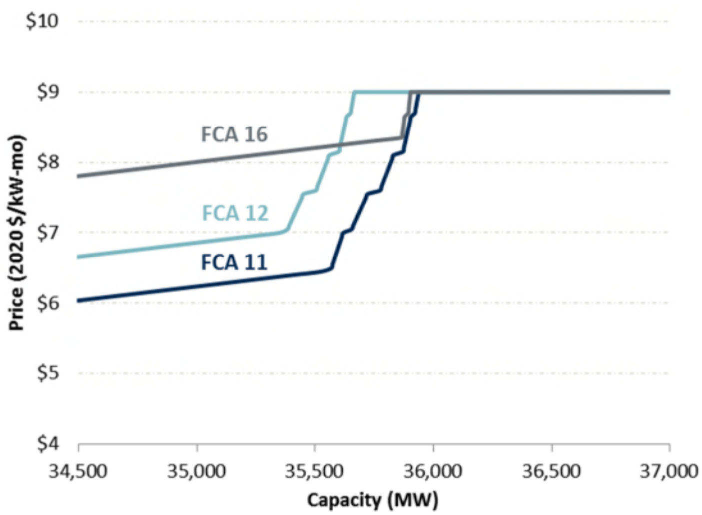
Since there is limited coal and nuclear capacity remaining online, we do not assume that the recent trend in retirements of these unit types will continue at the same pace. Instead, we base our assumptions for future baseline retirements on the approximately 1,400 MW of steam oil/gas that retired (or announced its retirement) over this seven-year period, corresponding to about 200 MW per year on average. Consequently, we assume 200 MW per year of retirements between 2020 and 2030, amounting to 2,200 MW out of 5,200 MW of coal-fired, oil-fired, and natural gas-fired steam units currently projected to be operating (after accounting for the planned retirement of Brayton Point 1–4 in 2017 and Bridgeport Harbor 3 coal plant in 2021).[89] We assume one third of that capacity would retire in Northern New England, in proportion to that zone's share of the 5,200 MW. In the absence of specific information about suppliers' retirement plans, this is a reasonable approach for projecting likely retirements in future years. Given the uncertainty, however, our sensitivity analyses test a range between 100 MW and 400 MW of annual retirements. For reference, [redacted]

[89] ISO New England (2016), 2016–2025 Forecast Report for Capacity, Energy, Loads, and Transmission, 2.1 Generator List, May 2, 2016. Available at: https://www.iso-ne.com/static-assets/documents/2016/05/2016_celt_report.xls.

[redacted].[90]

Figure 6 below shows how the supply curves change over the time frame analyzed. The most pronounced trend is the rise in offer prices from marginal oil- and gas-fired generators as ISO-NE increases its performance payment rate. The average offer of marginal oil- and gas-fired generators increases from $5.4/kW-mo in FCA 11 to $6.0/kW-mo in FCA 12 to $7.4/kW-mo in FCA 16 (for delivery year 2025/2026 and beyond).

Figure 6: Projected Supply Curves



Over time, the supply curves shift due to non-price retirements, energy efficiency and renewable additions. For example, the addition of 311 MW of energy efficiency and renewable capacity in FCA 12 is offset by 583 MW of existing supply retirements (including the recently announced 383 MW Bridgeport Harbor 3 coal plant) resulting in a net shift in the supply curve from FCA 11 to FCA 12 to the left by 272 MW. From FCA 12 to FCA 16, 1,037 MW of energy efficiency and renewable capacity additions are offset by 800 MW of retirements resulting in a shift to the right of 237 MW.

3. Capacity Market Clearing

We simulate each auction by intersecting the estimated supply and demand curves described above. As in the actual auctions, the intersection defines the clearing price and quantity. Both the supply and the demand curve will change from year to year. The demand curve shifts with load growth and with ISO-NE's transition to the new demand curve shape, as shown in Figure 3. The supply curve evolves as shown in Figure 6 above.

Figure 7 and Table 3 below show that in the near-term, total cleared capacity is expected to decline due to the transition from the linear demand curve utilized in FCA 10 to ISO-NE's less

90 LEI Report, p. 106.

rich transition curves starting in FCA 11. Between FCA 10 and FCA 13, we project that 1,600 MW of existing resources do not clear the market due to the shift in the demand curves, non-price retirements, and the addition of energy efficiency and renewable capacity. Starting in FCA 13, a steady increase in new energy efficiency and supply from existing resources that previously may have not cleared (or new capacity resources, such as demand resources or imports) match the annual load growth and maintain slight excess capacity above the Net ICR through FCA 15. Prices rise and capacity additions decrease in FCA 16 due to the second increase in the performance payment rate, which increases the projected marginal oil- and gas-fired capacity offers by $1.25/kW-mo. In FCA 18 through FCA 21, load growth and assumed non-price retirements push prices up to the assumed Net CONE value of $9/kW-mo, which results in nearly 1,600 MW of new natural gas-fired generators clearing the market. In our Base Case, Northern New England does not have enough surplus capacity for the NNE capacity price to be discounted from the system price.

Figure 7: Base Case Supply and Demand Balance

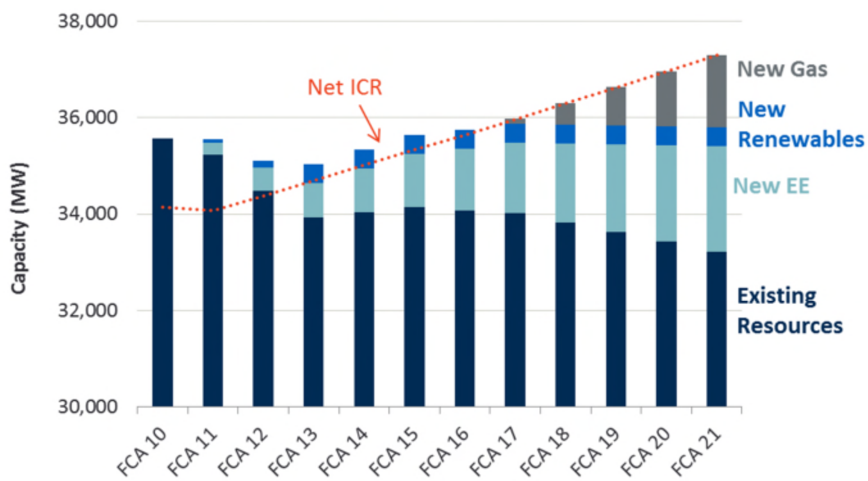
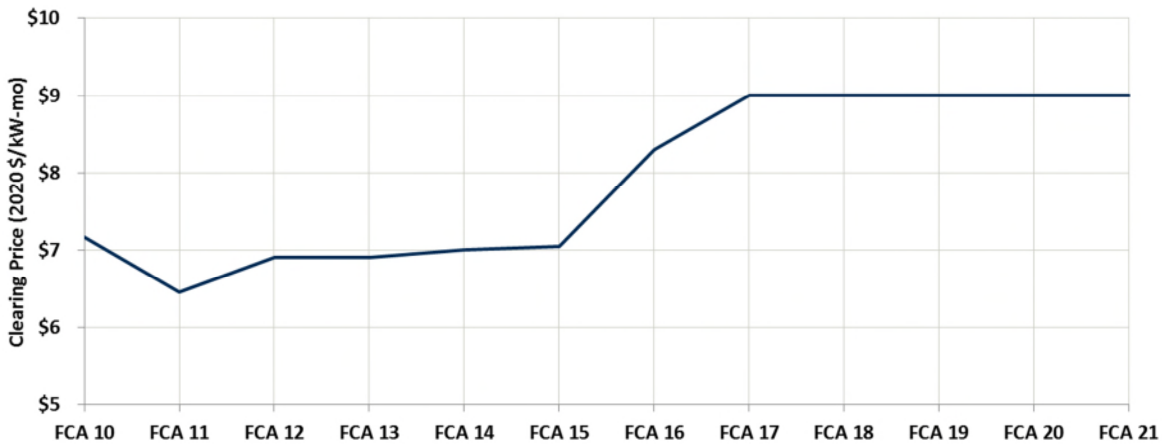


Table 3: Base Case Supply Projection

	FCA 10 2019-20	FCA 11 2020-21	FCA 12 2021-22	FCA 13 2022-23	FCA 14 2023-24	FCA 15 2024-25	FCA 16 2025-26	FCA 17 2026-27	FCA 18 2027-28	FCA 19 2028-29	FCA 20 2029-30	FCA 21 2030-31
Peak Demand (MW)												
Summer Peak net of PV	29,861	29,600	29,864	30,137	30,415	30,691	30,966	31,247	31,530	31,816	32,104	32,395
Net ICR	**34,151**	**34,075**	**34,378**	**34,693**	**35,013**	**35,331**	**35,648**	**35,971**	**36,297**	**36,626**	**36,958**	**37,292**
***Annual* Additions/Exits (MW)**												
Existing Resources	**35,567**	**-333**	**-758**	**-535**	**94**	**116**	**-72**	**-50**	**-200**	**-200**	**-200**	**-200**
Retirements (non-price responsive)	-	-200	-583	-200	-200	-200	-200	-200	-200	-200	-200	-200
Price Responsive Exits	-	-133	-175	-335	-	-	-	-	-	-	-	-
Price Responsive Entrants	-	-	-	-	+294	+316	+128	+150	-	-	-	-
New EE	**-**	**+251**	**+235**	**+220**	**+206**	**+192**	**+179**	**+179**	**+179**	**+179**	**+179**	**+179**
New Renewables	**-**	**+76**	**+76**	**+240**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
New Solar PV	-	+16	+16	-	-	-	-	-	-	-	-	-
New Onshore Wind	-	+60	+60	-	-	-	-	-	-	-	-	-
New Offshore Wind	-	-	-	+240	-	-	-	-	-	-	-	-
New Natural Gas-Fired Generation	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**+94**	**+347**	**+350**	**+353**	**+356**
Total Annual Additions/Exits		**-7**	**-447**	**-75**	**+300**	**+308**	**+107**	**+223**	**+326**	**+329**	**+332**	**+335**
Total Cleared Capacity (MW)	**35,567**	**35,560**	**35,113**	**35,038**	**35,338**	**35,646**	**35,752**	**35,975**	**36,301**	**36,630**	**36,962**	**37,297**

Figure 8 below shows that the Base Case capacity market prices will decline in the near-term due to the new demand curve and then steadily rise to $7/kW-mo until the increase in the performance payment rate in FCA 16 causes prices to jump above $8/kW-mo. New natural gas-fired generation enters the market starting in FCA 18, at which time the price settles at $9/kW-mo. The factors driving the Base Case were explained in more detail above, in Section II.B.

Figure 8: Base Case Capacity Market Clearing Price



B. Northern Pass Cases

Northern Pass could add as much as 1,000 MW of capacity into future ISO-NE capacity auctions, which will reduce capacity market prices and/or displace other capacity resources. There is substantial uncertainty about how the market would respond to NPT, so we developed four plausible scenarios, as described above. In the following sections, we further explain each scenario's assumptions and the amount of capacity that would clear in future capacity auctions, as well as capacity clearing prices.

1. Scenario 1: Supply Response without Retirements

In Scenario 1, the addition of NPT shifts the supply in the capacity market by 1,000 MW and results in a lower capacity price and a slight increase in cleared capacity. Similar to LEI's approach, we do not assume any permanent retirements due to the addition of capacity on NPT in this scenario (retirements are examined in Scenario 2 instead). However, we do model substantial temporary supply response that moderates the price impact.

For simplicity, we assume NPT offers capacity at a zero price and simply shifts the rest of the curve to the right. Figure 9 below shows that, at the system level, this shift results in only a 50 MW net increase in cleared capacity and a $0.30/kW-mo lower clearing price in FCA 13 compared to the Base Case (effects in the NNE zone are greater and interact with the system clearing, as discussed separately below). The addition of 1,000 MW from NPT is almost completely offset because supply is so elastic along the relatively flat section at the lower end of the supply curve, as discussed in Section III.A.2 above. In other words, there is a large amount of capacity unwilling to take on a capacity supply obligation if prices drop even modestly from the

Base Case level. This is the consequence of Performance Incentives and the Internal Market Monitor's revelation that 5,000 MW of oil-fired capacity is now offering around $5.50/kW-mo (and likely will increase their offers as the schedule performance payment rate increases in FCA 12 and FCA 16).[91]

Figure 9: Scenario 1 Supply Response to NPT Entry in Two Representative Years

(a) FCA 13 (b) FCA 17

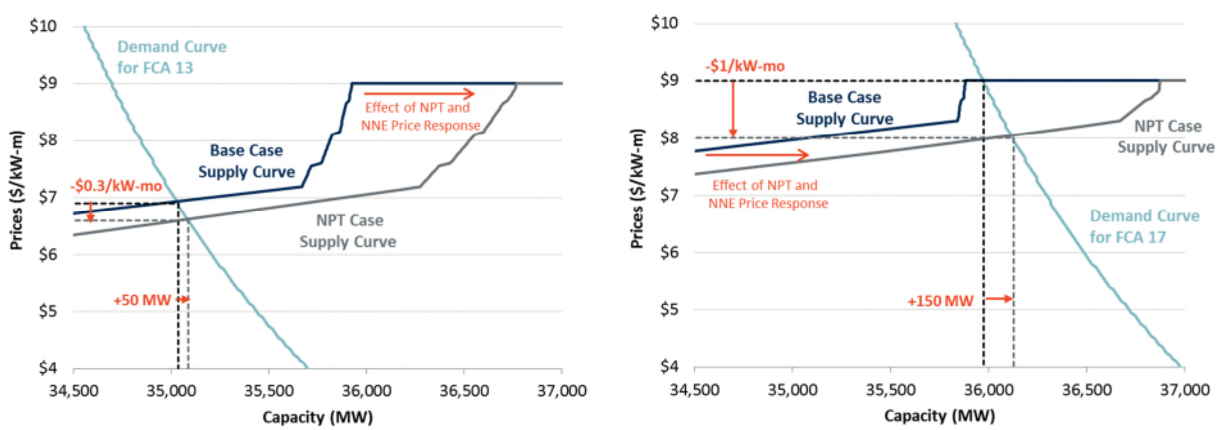


Table 4 below shows how the system-wide net increase in capacity evolves over time following the addition of NPT. In FCA 11, NPT displaces 950 MW of existing capacity that otherwise would clear the capacity market, such that the net increase in capacity is only 50 MW. From FCA 12 through FCA 16 the net addition is similar but slowly diminishing.[92] (See Appendix B for auction-by-auction supply and demand curves and clearing results.) For the three years following FCA 16, NPT has a larger impact on net capacity (and prices) as it defers the need for new capacity (at a much higher price corresponding to the cost of new entry) from FCA 17 to FCA 19. These trends are discussed further in Section IV.A.

Table 4: Scenario 1 Project Case Difference in Capacity from Base Case

	FCA 10 2019-20	FCA 11 2020-21	FCA 12 2021-22	FCA 13 2022-23	FCA 14 2023-24	FCA 15 2024-25	FCA 16 2025-26	FCA 17 2026-27	FCA 18 2027-28	FCA 19 2028-29	FCA 20 2029-30	FCA 21 2030-31
Difference from Base Case (MW)												
Northern Pass		+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000
Retirements		-	-	-	-	-	-	-	-	-	-	-
New Natural Gas-Fired Generation		-	-	-	-	-	-	-94	-441	-791	-997	-996
Other Price Responsive Additions/Exits		-950	-930	-950	-940	-950	-950	-756	-429	-99	-3	-4
Total Difference in Cleared Capacity		**+50**	**+70**	**+50**	**+60**	**+50**	**+50**	**+150**	**+130**	**+110**	**-**	**-**

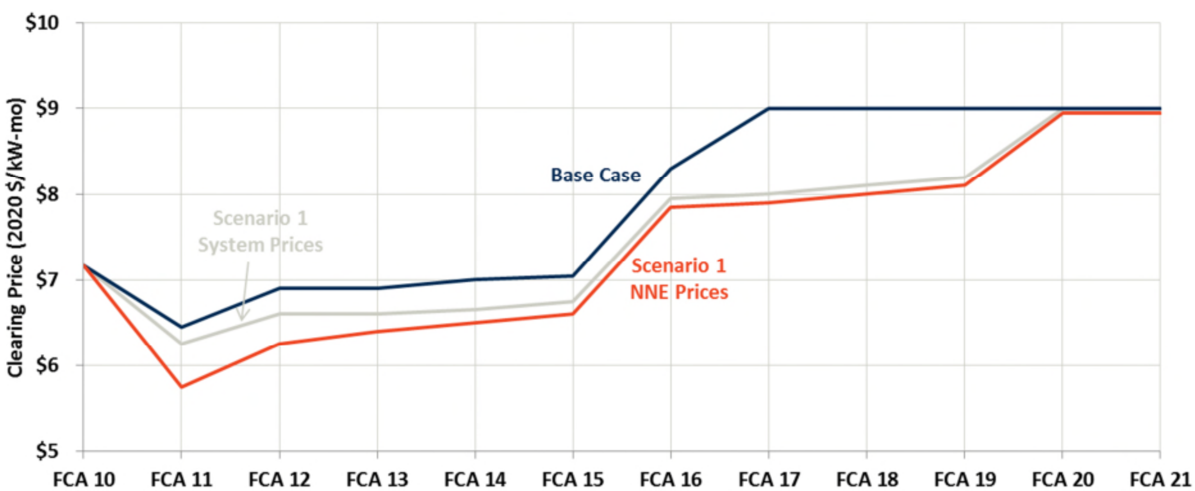
91 McDonald/Laurita Testimony, p. 3.

92 Although one might expect capacity price impacts to increase as load growth moves the demand curve rightward into the region of the Base Case supply curve with steeper supply, there are two effects working in the other direction: a leftward shift in the FCA 12 demand curve due to ISO-NE's transition to its new shape, and rising supply offer prices from marginal oil- and gas-fired generators as ISO-NE increases its performance penalty rate. See Figure 3 and Figure 6.

Although NPT may increase the net amount of capacity only modestly at the system level, it would increase the net amount of capacity in NNE more substantially (with the rest of system losing some capacity). We estimate that FCA 11 would equilibrate with 582 MW of existing capacity exiting in NNE as NPT enters, for a net gain of 418 MW there. The FCA 11 price in NNE with NPT would decrease along the NNE demand curve, ending up $0.50/kW-mo below the system price and $0.70/kW-mo lower than the system/NNE price in the Base Case. NNE's price separation from the system diminishes thereafter, however, as load growth and assumed baseline retirements reduce the capacity surplus in NNE, moving the supply curve back from the steep part of the NNE demand curve and reducing the sensitivity of prices to capacity additions via NPT. Thus, NNE's separation from the system price decreases to $0.35/kW-mo in FCA 12 to $0.20/kW-mo in FCA 13, then continues to fall to $0.05/kW-mo by FCA 20.

Overall, with the relatively flat supply curve and the lower cost of new entry we modeled, we find NPT would produce a substantially smaller price impact than LEI estimated. Figure 10 shows that NPT depresses capacity market prices in NNE by $0.45 to $0.70/kW-mo in the first six auctions, when both the Base Case and the Project Case have the capacity market clearing along the flattest section of the supply curve, and then by $0.90 to $1.10/kW-mo in the years in which NPT delays the need for new natural gas-fired capacity.

Figure 10: Scenario 1 Capacity Market Price Impact



Among the four scenarios we analyze, Scenario 1 results in the greatest impact of NPT on capacity market prices. This is because we assume capacity shipped via NPT qualifies and clears the capacity auction, and the only resources it displaces are marginal oil- and gas-fired generators that may mothball or may continue to operate without a capacity supply obligation. As demand grows, the displaced capacity returns to the market at lower prices than new generation would, helping to keep prices lower than in the Base Case (or than in Scenario 2, where some of the displaced capacity leaves permanently). Scenario 1 is plausible if the costs of mothballing and later re-activating capacity are relatively low or if the generators can justify operating for several years without a capacity payment, both of which seem fairly unlikely. For example, based on our analysis some of the capacity displaced in the first several auctions would remain out of the market for up to eight auctions before clearing again; it is likely that at least some of this capacity would instead choose to retire permanently and at a faster rate than assumed in the Base Case. We explore such an outcome in Scenario 2.

As for energy market and CO_2 emissions impacts of NPT in Scenario 1, we assume them to be similar to LEI's estimates. Even though our Scenario 1 has far more capacity displaced by NPT than LEI assumed, the displaced capacity is likely to be old oil-fired generation or other non-baseload capacity such as demand response. Oil-fired steam generators very rarely generate due to their high fuel costs, so their continued availability (or unavailability) has little effect on energy market outcomes. However, we adjust the LEI analysis to account for differences in the timing of new natural gas-fired combined-cycle plant entry. Because new generation enters in our Base Case in 2026, two years later than LEI projected, we assume that the energy market impacts that LEI found in their analysis from 2020 to 2024 continue for an additional two years and then taper off with additional entry of new generation through 2030. We provide more detail on our adjustments to LEI's energy market savings in Section IV.B below.

2. Scenario 2: Supply Response with Retirements

Like Scenario 1, Scenario 2 assumes NPT enables 1,000 MW of Hydro-Québec capacity to qualify and clear starting in FCA 11. However, in Scenario 2, NPT's entry is assumed to induce 500 MW of existing non-baseload capacity resources to permanently retire. Of the 500 MW, we assume 34% (170 MW) is located in the NNE zone, proportional to the distribution of at-risk fossil-fired capacity in New England.[93] In addition to this induced retirement, another 490 MW of price-responsive supply will fail to clear, such that the total amount of capacity clearing is only 10 MW greater than in the Base Case in FCA 11. Figure 11 below illustrates the market clearing for FCA 11 following the entry of NPT. The net effect is similar to adding only 500 MW in FCA 11 without any retirements,[94] but with a greater impact in NNE, where 1,000 MW of capacity is added but we assume only one third of the 500 MW of induced retirements occur in NNE.

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93 The New England system has about 5,200 MW of coal-fired, oil-fired, and natural gas-fired steam units currently projected to be operating (after accounting for the planned retirement of Brayton Point 1–4 in 2017 and Bridgeport Harbor 3 coal plant in 2021), and 1,700 MW of these are located in Northern New England. ISO New England (2016), 2016–2025 Forecast Report for Capacity, Energy, Loads, and Transmission, 1.1 Summer Peak Capabilities and Load Forecast (MW), May 2, 2016. Available at: https://www.iso-ne.com/static-assets/documents/2016/05/2016_celt_report.xls.

94 The expert testimony submitted in support of the New England Clean Power Link assumed that just 500 MW out of 1,000 MW would qualify under ISO-NE rules: "I conservatively assumed that the NECPL would allow shippers to qualify only 500 MW as capacity under ISO-NE rules for FCM, halfway between the NECPL's full 1,000 MW of line capacity and zero, due to uncertainty factors of: (i) uncertain transmission upgrades that will be required in order for NECPL energy to be considered deliverable and thus qualify as capacity; and (ii) potential market responses…that could dilute NECPL's capacity value." Seth G. Parker (2014), Petitioner's Prefiled Direct Testimony of Seth G. Parker on Behalf of Champlain VT, LLC, before the State of Vermont Public Service Board, in the

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Figure 11: Scenario 2 Supply Response to NPT Entry in FCA 11

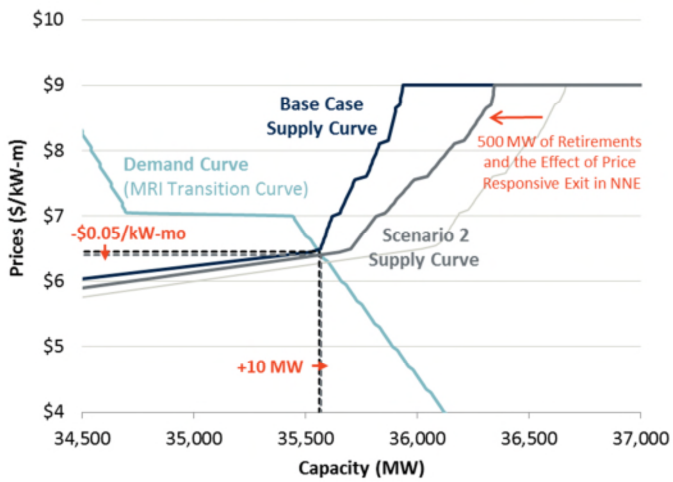


Table 5 shows how the impacts change over time in Scenario 2. Similar to Scenario 1, the case with NPT continues to have a relatively small incremental capacity effect on the system through FCA 16. New capacity is deferred for just a single year in Scenario 2, resulting in FCA 17 clearing an additional 110 MW of capacity in the Project Case.

Table 5: Scenario 2 Project Case Difference in Capacity from Base Case

	FCA 10 2019-20	FCA 11 2020-21	FCA 12 2021-22	FCA 13 2022-23	FCA 14 2023-24	FCA 15 2024-25	FCA 16 2025-26	FCA 17 2026-27	FCA 18 2027-28	FCA 19 2028-29	FCA 20 2029-30	FCA 21 2030-31
Difference from Base Case (MW)												
Northern Pass		+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000
Retirements		-500	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500
New Natural Gas-Fired Generation		-	-	-	-	-	-	-94	-441	-496	-505	-504
Other Price Responsive Additions/Exits		-490	-470	-490	-480	-470	-470	-296	-9	-4	+5	+4
Total Difference in Cleared Capacity		**+10**	**+30**	**+10**	**+20**	**+30**	**+30**	**+110**	**+50**	**-**	**-**	**-**

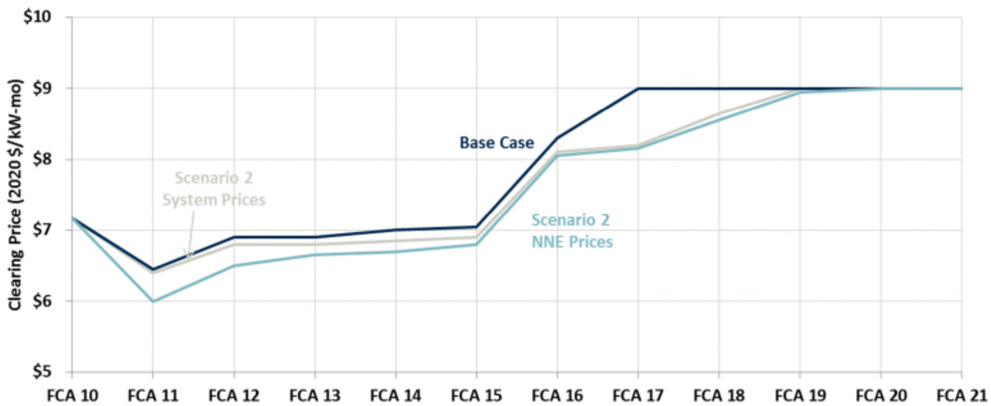
Price separation between NNE and the rest of the system is similar to Scenario 1 but slightly less because the NNE supply curve shifts rightward by 830 MW (1,000 MW minus 170 MW of induced retirements in NNE) rather than the full 1,000 MW. For example, in FCA 11, the NNE price is discounted by $0.40/kW-mo compared to $0.50/kW-mo in Scenario 1. However, the system price, from which NNE is discounted, is higher in Scenario 2—only $0.05/kW-mo below the Base Case versus $0.20/kW-mo below in Scenario 1. This tepid initial effect at the system level occurs because the combination of 500 MW of induced retirements and NNE's price-responsive exits offsets much of NPT's 1,000 MW shift in the system supply curve. Over time, NNE becomes less constrained due to local load growth and baseline retirements. NNE's discount from the system price diminishes and less price-responsive exit occurs there. This allows NPT's impact on the system price to grow over time. The price impact is greatest in FCA

Continued from previous page

matter of the New England Clean Power Link Project ("NECPL"), Docket No. 8400, December 8, 2014.

17 when the system needs new capacity in the Base Case but not yet with NPT, so prices do not yet rise to Net CONE. However, that delay is two years in Scenario 2, compared to three years in Scenario 1. Figure 12 shows the price trajectory.

Figure 12: Scenario 2 Capacity Market Price Impact



Similar to Scenario 1, we assume in this case that the resources that retire are non-baseload units that rarely produce energy and thus have limited impact on energy market prices.[95] We therefore do not adjust LEI's estimates of energy market savings for the assumed retirement in this scenario. However, we do adjust the energy savings to account for differences in the timing and quantities of new natural gas-fired combined-cycle plants entering the market. Compared to Scenario 1, in this scenario, 500 MW more new natural gas-fired combined-cycle generation additions occur to replace the capacity that retired in FCA 11 upon NPT's entry in the Project Case. The additional supply of low-cost energy from the new natural gas-fired combined-cycle generation will sustain the energy market savings over a longer period of time than in Scenario 1.[96]

3. Scenario 3: NPT Does Not Qualify or Does Not Clear FCA

In Scenario 3, we assume that Hydro-Québec resources made deliverable by NPT either do not qualify as capacity, or that they qualify but do not clear the FCA. Thus they would not reduce capacity prices, although they would still sell energy much of the time and reduce energy prices. The reduction in energy prices in this scenario could actually increase capacity prices slightly, as discussed in Section IV.A below. This scenario represents a real possibility, given the uncertainty about whether shippers over NPT will be able to demonstrate sufficient winter capability (when Québec's own system load peaks) to qualify the full capacity and how ISO-NE's

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95 Several steam oil/gas units with capacity between 400 and 600 MW fall into this category and could retire in response to NPT, including Canal 1, Canal 2, Middletown 4, Montville 6, Mystic 7, Newington 1, New Haven Harbor, and Yarmouth 4. ISO New England (2016), 2019–2020 Forward Capacity Auction Obligations, April 13, 2016. Available at: https://iso-ne.com/static-assets/documents/2016/02/fca_10_obligations.xlsx

96 See Section IV.B for further discussion of energy market savings across scenarios.

market monitor might mitigate the capacity market offer price upward under its "buyer market power" rules to prevent an uncompetitively low capacity clearing price.

a. Resource Qualification

To participate in the ISO-NE capacity market, suppliers must first complete several steps to qualify their resources with ISO-NE and submit their bids into the auction. New resources must submit to ISO-NE a "Show of Interest" in the spring of the year prior to the auction to qualify for an auction.[97] Submitted bids may then be subject to review by the Internal Market Monitor to ensure that a submitted bid reflects the costs of the bidding resources.

To qualify in the ISO-NE FCM as an Elective Transmission Upgrade, the shippers of capacity across NPT, presumably Hydro-Québec, will have to demonstrate to ISO-NE that there is either a dedicated resource to serve New England load or sufficient capacity across the entire exporting system to serve New England up to its capacity supply obligation at any time throughout the year.[98] In Québec, surplus capacity is more limited in the winter since Québec's own demand peaks then. ISO-NE will only qualify an Elective Transmission Upgrade up to the lower of the winter and summer capacity capability values. Alternatively, resources can qualify more capacity than the minimum of their Seasonal Claimed Capabilities if they submit a joint offer with other complementary resources that can provide additional capacity in the winter months.[99] Many generators in New England have greater winter capability than summer and so might be candidates for such arrangements.[100] However, such arrangements could add to the challenges NPT may face in submitting a competitive offer and clearing the market, as we discuss below.

The Applicants have not provided evidence to confirm that Hydro-Québec has sufficient surplus capacity in the winter to qualify as capacity, nor have they provided evidence of commercial arrangements with complementary resources to submit a composite offer into the capacity auctions. Based on our review of publicly-available data, it is unclear whether Hydro-Québec will have sufficient surplus to qualify capacity to export to New England. One indicator that

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97 ISO New England (2015), Forward Capacity Auction #12 Schedule, Capacity Commitment Period: 2021–2022, August 6, 2015. Available at: https://www.iso-ne.com/static-assets/documents/2015/08/fca_12_market_timeline_new_auction_date_8_6_2015.pdf

98 "The Project Sponsor shall…submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource." ISO New England (2016), Market Rule 1, Sec III.13.1.3.5.3. Available at https://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1

99 ISO New England (2016), Market Rule 1, Section III.13.1.5. Available at https://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1

100 Currently 15 generation facilities clear at least 10 MW more capacity in the winter months than in the summer months resulting in 493 MW of additional capacity. ISO New England (2016), 2019–2020 Forward Capacity Auction Obligations, April 13, 2016. Available at: https://iso-ne.com/static-assets/documents/2016/02/fca_10_obligations.xlsx

Hydro-Québec may ***currently*** lack year-round surplus capacity is that it sells less capacity into ISO-NE than the transfer capability on its two existing lines into New England would allow.

- The Phase II intertie from Hydro-Québec through Vermont to Massachusetts is rated at 1,400 MW,[101] but it provided only 1,141 MW of capacity in the latest capacity auction (FCA 10) and 1,119 MW in the previous auction (FCA 9).[102] The details of Phase II's participation are unique and somewhat complicated, however. Some of the capacity on the Phase II intertie is not offered as regular supply into the capacity auctions but instead credited before the auction to the New England entities that own the capacity rights through Hydro-Québec Interconnection Capacity Credits (HQICCs).[103] Prior to the latest auction, ISO-NE estimated the HQICCs were 975 MW,[104] leaving approximately 425 MW of transfer capability available for Hydro-Québec to sell additional capacity into the auction. However, only 166 MW cleared, leaving 259 MW unused and suggesting Hydro-Québec did not have the capacity to serve New England.
- Similarly, the rated capacity for the Highgate intertie, the second line between Québec and New England, is 200 MW but just 58 MW of summer capacity cleared in ISO-NE's latest capacity auction and 52 MW cleared in FCA 9.[105] The Highgate intertie does not have an arrangement similar to the HQICCs for the Phase II intertie.
- In addition, the Hydro-Québec import capacity across Phase II is 19 MW lower in the winter months than in the summer months. Across Highgate it is 52 MW lower during

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[101] ISO New England (2016), ISO New England Installed Capacity Requirement, Local Sourcing Requirements and Capacity Requirement Values for the System-Wide Capacity Demand Curve for the 2019/20 Capacity Commitment Period, January 2016, p. 36. Available at: https://www.iso-ne.com/static-assets/documents/2016/01/icr_values_2019_2020_report_final.pdf

[102] These values are lower than the total Phase II capacity that participated in FCA 6 through 8. In FCA 6 and FCA 7 the total capacity was 1,400 MW and in FCA 8, 1,314 MW. Auction-by-auction capacity results are available on ISO-NE's website at: https://www.iso-ne.com/markets-operations/markets/forward-capacity-market

[103] The amount of HQICCs is calculated prior to each auction by ISO-NE based on the tie benefits provided by Phase II intertie and are deducted both from the ISO-NE Installed Capacity Requirement (ICR) to calculate the Net Installed Capacity Requirement and from the portion of the ICR allocated to the owners of the capacity rights. Tie benefits are a probabilistic measure of reliability value from non-firm energy imports. Benefits attributed to HQICCs are made unavailable for firm capacity imports.

[104] ISO New England (2016), ISO New England Installed Capacity Requirement, Local Sourcing Requirements and Capacity Requirement Values for the System-Wide Capacity Demand Curve for the 2019/20 Capacity Commitment Period, January 2016, p. 4. Available at: https://www.iso-ne.com/static-assets/documents/2016/01/icr_values_2019_2020_report_final.pdf

[105] The cleared Highgate capacity was higher in FCA 6 through 8: 194 MW in FCA 6, 91 MW in FCA 7, and 111 MW in FCA 8. Auction-by-auction capacity results are available on ISO-NE's website at: https://www.iso-ne.com/markets-operations/markets/forward-capacity-market

the winter when compared to the summer months.[106] While the difference is relatively small, this suggests that there may be limited capacity during Hydro-Québec's peak load conditions to serve the New England capacity market.

We also examined publicly-available documents on Hydro-Québec's supply, demand, and external obligations, but those presented mixed indicators that we have not been able to reconcile:

- *Negative:* Hydro-Québec Distribution company released its 10-year Electricity Supply Plan in October 2015 showing its system will be short of capacity to serve its internal winter-peaking load starting in 2016 and continuing until 2022.[107]
- *Positive:* Hydro-Québec's system installed capacity (including both its internal installed capacity and contracted resources, such as Churchill Falls) appears to exceed 45,500 MW, which is about 2,000 MW above the peak demand plus reserve margin projected for 2020 by Hydro-Quebec Distribution.[108] However, it is unclear whether all of the hydro capacity can be relied on at its installed capacity due to the impacts of future reservoir levels, cooling water temperatures, and ice cover formation on dependable capacity.[109]
- *Positive:* Hydro-Québec reports in the 2014 Quebec Balancing Authority Area Comprehensive Review of Resource Adequacy that there will be 45,268 MW of capacity available to serve 39,489 MW of load, including exports. This suggests that there are over 5,000 MW of capacity available for additional exports.[110]

b. Capacity Offer Mitigation

If Hydro-Québec qualifies to sell additional capacity into New England, its offers will be subjected to review and possible mitigation by the Internal Market Monitor. The Internal Market Monitor reviews all offers by Elective Transmission Upgrades such as NPT.[111] The purpose of the Internal Market Monitor's review is to prevent capacity from offering at un-competitively low prices, supported by out-of-market contracts intended to suppress market prices. To inform the review, shippers will need to submit detailed net cost projections for their

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106 ISO New England (2016), 2019–2020 Forward Capacity Auction Obligations, April 13, 2016. Available at: https://www.iso-ne.com/static-assets/documents/2016/02/fca_10_obligations.xlsx

107 Hydro-Québec (2016), Capacity and energy needs, http://www.hydroquebec.com/sustainable-development/energy-environment/capacity-energy-needs.html, accessed December 14, 2016.

108 Hydro-Québec (2015), Annual Report 2015: Setting new sights with our clean energy, p. 100. We derated the wind capacity by 40% based on the source in the previous footnote.

109 Hydro-Québec Distribution (2014), NPCC 2014 Québec Balancing Authority Area Comprehensive Review of Resource Adequacy, December 2, 2014, p. 29. Available at: https://www.npcc.org/Library/Resource%20Adequacy/Qu%C3%A9bec%20Comprehensive%20Review%202014_RCC%20Approved%20December%202%202014.pdf

110 *Id.*, p. ii.

resources. Key elements include the capital and other fixed costs of the transmission in both the U.S. and Canada and the cost of any new generation capacity needed to support the transaction, both amortized over some reasonable time period (likely 20 years, similar to the Internal Market Monitor's treatment of generators). Finally, the ***net*** cost of providing capacity to New England is reduced by any net energy revenues the transmission and generation would enable. The Internal Market Monitor assesses these issues based on a projected wholesale market price for energy in New England minus any variable cost or opportunity cost for Hydro-Québec to provide the energy. Potential contract prices for the energy or clean energy attributes provided across NPT, if any, cannot be counted in place of the wholesale market price. Any value placed on the clean energy attributes of the imported hydro generation would not be counted unless they are "broadly available" to other resources, such as the Renewable Energy Certificate (REC) payments that are available to wind, solar, and biomass resources.

The Internal Market Monitor's last step in determining a competitive offer price is to translate the annual net cost (from above) into a capacity supply offer in terms of cost per kW-month. This involves dividing by the number of kW-months the resource can be relied on to serve the New England market. If the hydro resources in Québec are not able to qualify to provide firm capacity throughout the year because they lack adequate winter capability, they can qualify for the market by submitting a joint offer with another resource providing winter capability (such as a New England generator whose winter rating is higher than its summer rating). In that case, the net costs associated with NPT-enabled capacity have to be divided by the smaller number of kW-months that NPT actually provides capacity, leading to a higher offer price.

Based on its review, the Internal Market Monitor will set the prices by which shippers can offer into the market. If it determines that a low offer price is justified, the capacity across NPT is likely to clear the market. However, if the offer is mitigated by the Internal Market Monitor to a sufficiently high price, the capacity may not clear. Finally, it is possible that an upwards-mitigated offer price could set the capacity market price in the auction, which would lead to a result somewhere between the case of NPT clearing and NPT not clearing the auction.

If the capacity offered by shippers on NPT into the capacity market does not clear, or if it does not qualify in the first place, the capacity market impact of NPT (relative to the base case) will be zero. We find this outcome to be at least plausible due to the limited winter capability in the Hydro-Québec system, which could limit the capacity that can be offered and the number of months in which it can reliably serve the New England system. Furthermore, we cannot predict the outcome of the Internal Market Monitor's review since the Applicants have not provided evidence to support their assumption that the shippers on NPT will be able to support a low offer into the capacity market that can pass the Internal Market Monitor's mitigation criteria.

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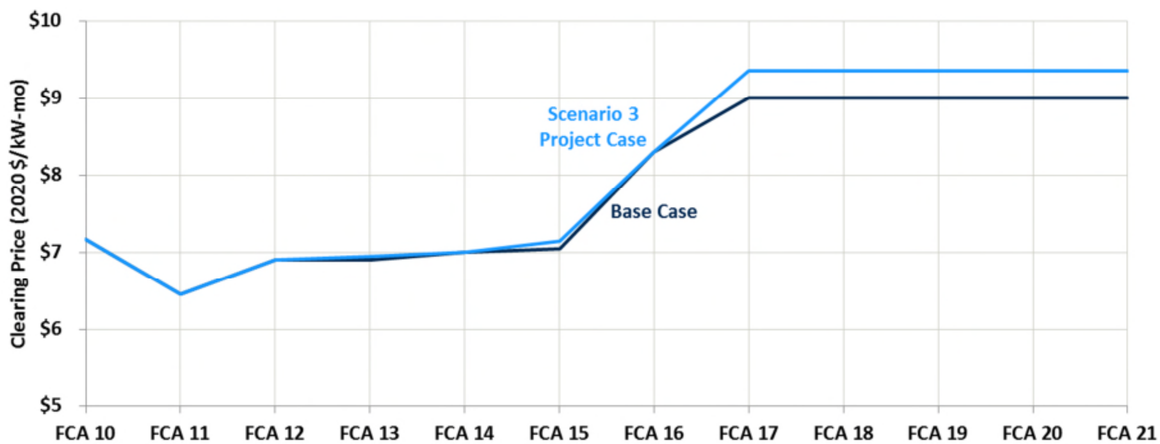
111 ISO New England (2016), Market Rule 1, Section III.A.21.1.1. Available at https://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1

c. *Consequences if NPT Capacity Does Not Clear*

Even if NPT did not clear the capacity market, it would still provide energy price and GHG emissions impacts. In fact, since natural gas capacity is likely to be added in the same years in both the Base Case and Project Case (as NPT has no impact on capacity market outcomes) we assume that the energy market impacts that LEI estimated in the first few years after NPT enters will be sustained throughout the time frame analyzed, with no offsetting generation displacement, as in Scenarios 1 and 2. For that reason, Scenario 3 has the highest energy market impacts of the scenarios. However, Figure 13 below shows that Scenario 3 has a countervailing effect where lower energy prices increase capacity prices from FCA 17 onward, as we explain in Section IV.A.

Figure 13: Scenario 3 Capacity Market Price Impact



We should note that while Scenario 3 assumes no NPT capacity is able to clear the market, it is also possible that the cleared quantity could be higher than zero but still less than the full amount assumed by LEI. In that case, the impact would be between this scenario and Scenarios 1 and 2.[112]

4. Scenario 4: NPT Displaces a Similar Resource

States across New England are pursuing new clean energy resources to reduce electric power sector GHG emissions and to reduce the region's dependence on natural gas-fired generation. For example, Massachusetts recently passed legislation to solicit proposals for 1,200 MW of new large-scale hydropower and/or Class I renewables (primarily wind and solar) contracts and, separately, for 1,600 MW of offshore wind.[113]

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112 As noted above, if 500 MW of NPT capacity clears instead of 1,000 MW then the wholesale market impacts will be similar to our Scenario 2.

113 Office of the Governor of Massachusetts (2016), "Governor Baker Signs Comprehensive Energy Diversity Legislation," Press Release, August 8, 2016. Available at

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In Scenario 4 the addition of NPT has no significant impact on the New England energy and capacity markets because it is assumed to displace other clean energy resources competing in the same solicitations. The resource displaced could be another transmission project with access to Canadian hydropower, or it could be a combination of wind and solar (or other renewable) projects. While each resource would have slightly different characteristics, and the potential impacts of NPT alone are uncertain (as demonstrated in the previous three scenarios), we find that they are likely to have similar effects on the energy and capacity markets. In other words, the net benefits of NPT would be essentially zero if it pushed other clean energy resources of a similar scale out of the market. We review the different potential outcomes for each resource type below.

NPT Displaces Alternative Hydro Line: Several transmission lines like NPT are being pursued to increase the capacity between hydro resources in Québec and load in New England. They are in various stages of development, and not all are likely to be completed. The furthest advanced project is the New England Clean Power Link (NECPL), which connects to the Hydro-Québec system in northwestern Vermont, runs along the bottom of Lake Champlain, and interconnects to the New England system in southern Vermont. The NECPL provides similar capacity to NPT but has already obtained state and federal permits for constructing the line.[114] It is reasonable to expect that the project can compete in Massachusetts's upcoming solicitation for large-scale hydropower or renewables.

Other transmission projects have been proposed to connect resources in northern New York and Vermont (*e.g.*, Vermont Green Line)[115] and resources in Maine with load in southern New England (*e.g.*, Maine Green Line).[116] If the addition of NPT results in an alternative line not being built, the electricity market and capacity market price impacts of NPT will be close to zero, as any reductions in capacity and energy prices and GHG emissions would likely be similar in both the case with NPT and the case without NPT.

The viability and relative costs of alternative projects must be carefully considered to assess the probability of an alternative line being built in the absence of NPT. While NECPL has received

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Continued from previous page

http://www.mass.gov/governor/press-office/press-releases/fy2017/governor-baker-signs-comprehensive-energy-diversity-law.html

114 The NECPL developer TDI New England received the Certificate of Public Good from the Vermont Public Service Board in January 2016 (see: http://psb.vermont.gov/sites/psb/files/orders/2016/January/8400%20CPG.pdf), permits from the Army Corps of Engineers in February 2016 for building the project across various waterways, including Lake Champlain, and the U.S. Department of Energy Presidential Permit in December 2016 (see: http://www.necplink.com/docs/press_releases/The_New_England_Clean_Power_Link_Receives_Presidential_Permit.pdf).

115 For more information, see: http://vermontgreenline.com/

116 For more information, see: http://mainegreenline.com/

several necessary permits, the developers indicate they are still negotiating with potential shippers and off-takers for use of the capacity and have not secured financing.[117] In this regard, NPT is a more advanced project;[118] on the other hand, NPT must still receive some of the federal and state permits already obtained by NECPL.

We also considered whether there is a case where NPT and an alternative hydro project are both built. This outcome is possible if both Massachusetts and Connecticut procure hydro resources to meet a portion of their energy demand. In such a case, NPT would expand the supply of clean energy into New England without necessarily displacing other similar projects. Its incremental impacts on market prices would then be similar to those in Scenarios 1, 2, and 3, but likely slightly lower due to the diminishing marginal effects of adding clean energy resources to the New England market.

NPT Displaces New Renewable Resources: If hydro resources are not imported from Québec, investments in renewables in New England would need to increase in order to achieve similar GHG reductions.[119] The competition between renewables and large-scale Canadian hydro is evident in the recent New England Clean Energy RFP and the recently passed Massachusetts procurement that allows for competition between these resources.[120]

The different generation profiles of large-scale hydro and renewable resources are important to consider when evaluating the different market outcomes in this case. Large-scale hydro would most likely provide energy during all on-peak hours, with a relatively stable production profile and fairly dependable output during most scarcity conditions in the New England system. Renewables, on the other hand, would generate intermittently at lower capacity factors and with a more variant production profile, depending on the availability of wind and sunlight. Renewables' intermittent generation patterns limit their ability to reliably operate during shortage conditions, thus reducing their capacity value to a fraction of their nameplate capacity. ISO-NE rates wind at 30% of nameplate capacity and solar at 16%. NPT might have more capacity value and capacity price impact if it qualifies and clears its full amount, or it could provide less for the reasons described in Scenario 3.

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117 TDI New England targets Winter 2016–17 for finalizing a transmission service agreement and completing project financing. See: http://www.necplink.com/schedule.php

118 NPT has already signed a transmission service agreement, and the shippers have agreed to a delivery performance agreement. An offtake agreement with New Hampshire load for a limited quantity of the energy to be imported across NPT has been negotiated but not yet approved by New Hampshire regulators.

119 Increased energy efficiency efforts are likely to also play a role in reducing GHG emissions, but not at the scale of lines like NPT.

120 For more on the Massachusetts procurements, see: http://www.mass.gov/governor/press-office/press-releases/fy2017/governor-baker-signs-comprehensive-energy-diversity-law.html. For more on the New England Clean Energy RFP, see: https://cleanenergyrfp.com/

As for energy market impacts, both types of resources are likely to have similar effects, assuming a similar total amount of clean energy produced. Both have very low variable costs and would displace higher cost natural gas-fired generation on the margin and slightly lower the clearing price. Their effects would differ slightly depending on when the mix of renewables would generate electricity and how sensitive prices are during those hours to changing supply. Overall, NPT might lower electricity prices more or less than alternative renewable resources. Its net impact would be very limited relative to Scenarios 1 and 2.

NPT Not Likely to Displace Nuclear: We also considered whether NPT could lead to the retirement of additional New England nuclear plants. We believe that this is unlikely—in any case a lower risk than the other downside factors reflected in our scenarios. The three nuclear generation units that are expected to remain in operation in 2020 are Seabrook (1,247 MW in New Hampshire, licensed through 2030), Millstone 2 (875 MW in Connecticut, licensed through 2035), and Millstone 3 (1,225 MW in Connecticut, licensed through 2045).[121] We have not comprehensively analyzed whether these plants are at risk for retirement because we lack information on costs and other factors we would need to conduct such an analysis. However, we see some positive indicators for their viability and, in any case, the introduction of NPT would only marginally affect their viability, as discussed below. And if the plants were to become unviable, there is some possibility that their host states might step in to keep them operating in order to avoid losing a vast amount of carbon-free generation that is important for meeting their decarbonization goals (among other reasons).

There are some indicators of the likely future viability of these nuclear generation sources. Utility analysts at UBS estimated the levelized costs of Millstone Units 2 and 3 to be near $40/MWh.[122] The costs of Seabrook may be several dollars lower since it is a larger and newer unit.[123] On the revenue side, Potomac Economics, the ISO-NE External Market Monitor, analyzed the projected revenues of nuclear units in New England and concluded that revenues for nuclear generation have decreased over the past several years but are likely to rise to around

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121 For nuclear license periods, see NRC websites for each unit: U.S. Nuclear Regulatory Commission (2016), List of Power Reactor Units, http://www.nrc.gov/reactors/operating/list-power-reactor-units.html, accessed December 14, 2016. For capacity of nuclear units, see: ISO New England (2016), 2019–2020 Forward Capacity Auction Obligations, April 13, 2016. Available at: https://iso-ne.com/static-assets/documents/2016/02/fca_10_obligations.xlsx

122 UBS (2016), "Dominion Resources: Feasting on ITCs from the Millstone," Global Research, May 24, 2016. The projected fuel price for Millstone is $8.50/MWh and O&M costs are $230/kW-year. Assuming 90% capacity factor, the levelized cost of continued operations are $37.50/MWh.

123 These estimates appear consistent with fuel and operating cost data from Energy Velocity and capital costs expenditures based on 2015 average costs calculated by NEI. Nuclear Energy Institute (2016), Nuclear Costs in Context, April 2016. Available at: http://www.nei.org/CorporateSite/media/filefolder/Policy/Papers/Nuclear-Costs-in-Context.pdf?ext=.pdf

$50/MWh in 2019 and 2020, when NPT would enter the market.[124] At these market prices, the economics of nuclear plants will depend on the size of the plant and whether it has multiple units.[125] Both of the remaining nuclear plants in New England are substantially larger than the two plants that recently retired (or announced retirement) and thus are more likely to remain financially viable at the higher capacity prices that begin in 2017.

Regarding the potential impact of NPT on nuclear plants' viability, suppressed wholesale energy and capacity prices could have an effect, but only a very marginal one. We estimate that NPT could reduce Seabrook's revenues by an average of $2.0/MWh in Scenario 1, by $1.6/MWh in Scenario 2, and by $1.1/MWh in Scenario 3 over the first five years of NPT's operation. This impact is relatively small compared to the overall costs and revenues of a nuclear plant, and compared to uncertainties stemming from natural gas and capacity prices. For example, the difference in Seabrook energy market revenues between the two natural gas prices in LEI's analysis would exceed $10/MWh. A $2/kW-mo change in capacity prices for any reason, which is possible with or without NPT, would affect Seabrook's revenues by $5/MWh. We provide these values to bring perspective to the potential impact of NPT. While lower wholesale prices due to NPT will reduce revenues to all existing suppliers, we find it to be unlikely that the short-term wholesale market impact of NPT would be the primary cause of the retirement of an additional nuclear plant in New England.

It is also important to consider that if the nuclear plants' viability becomes threatened, some states might move to keep the facilities operating to preserve their vast amount of carbon-free generation (and save jobs). Illinois recently passed a bill to support its nuclear plants that had planned to retire. The New York Public Service Commission recently approved a mechanism to support its at-risk nuclear plants by buying Zero Emission Credits from them (although that is subject to legal challenges). In Connecticut, the State Senate considered a bill that would allow existing nuclear facilities to compete against renewable resources and large-scale hydro for future clean energy contracts and their associated extra payments.[126] We are not aware of any similar initiatives in New Hampshire.

IV. Impacts on Electric Customers' Costs and Suppliers' Revenues

In the previous section, we developed four scenarios that account for the biggest uncertainties related to the introduction of NPT, and we presented the impacts on cleared quantities and prices

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124 David Patton, Pallas LeeVanSchaick, and Jie Chen (2016), 2015 Assessment of the ISO New England Electricity Markets, External Market Monitor for ISO-NE, June 2016, p. 45. Available at: https://www.iso-ne.com/static-assets/documents/2016/06/isone_2015_emm_report_final_6_14_16.pdf

125 *Id.*, p. 50.

126 Connecticut General Assembly (2016), SB 344: An Act Requiring a Study of the Adequacy of Energy Supplies in the State, Session Year 2016. Available at: https://www.cga.ct.gov/ASP/CGABILLSTATUS/cgabillstatus.asp?selBillType=Bill&bill_num=SB344.

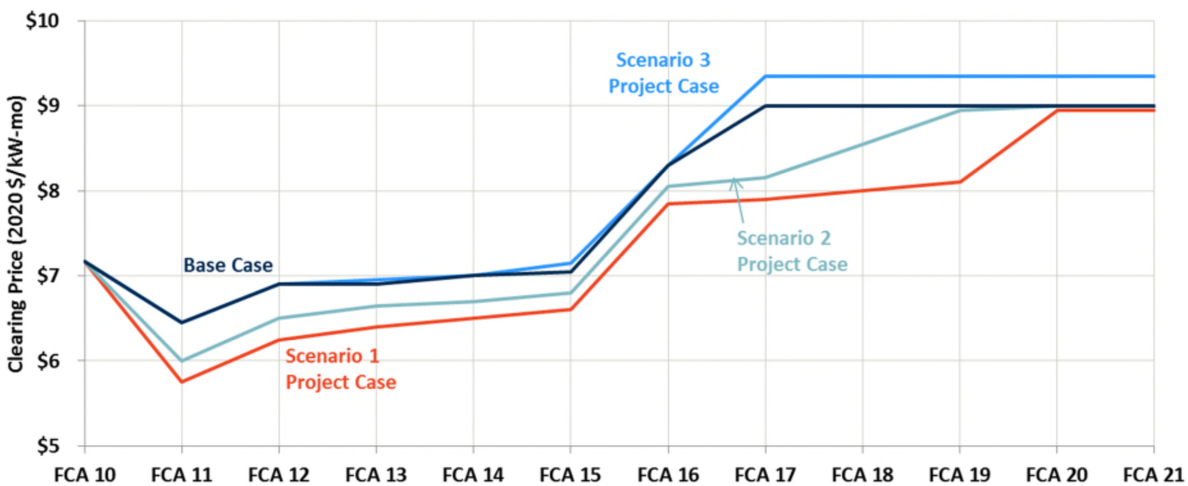
in the wholesale capacity market. In this section, we summarize the capacity price impacts across scenarios and present several sensitivity analyses to uncertain and important market parameters. We then present energy market price impacts, including how we adapted LEI's results. Finally, we present the total estimated savings on customer bills and the revenue loss to suppliers.

As LEI did, we present two types of metrics: the 11-year annual average and the net present value over the first 11 years.[127] The average annual impact is perhaps more intuitive, but it masks the time profile of savings and the time value of money.[128] Hence we also report the results in terms of the net present value over the first 11 years after NPT is built.

A. WHOLESALE CAPACITY MARKET PRICE IMPACTS

Figure 14 summarizes our results for the capacity market prices in the Base Case and the three scenarios (Scenario 1, Scenario 2, and Scenario 3) with price differences from the Base Case. The Scenario 4 prices are the same with and without NPT.

Figure 14: Capacity Market Prices by Scenario (in NNE)



In all scenarios analyzed, capacity prices drop in FCA 11 due to a shift in the demand curves as ISO-NE transitions to the new, left-shifted demand curves and lower projected peak load. Prices then recover in FCA 12 with the increase in marginal oil- and gas-fired generators' offer prices, reflecting the higher performance penalty rate (increasing from $2,000/MWh to $3,500/MWh). The prices then increase steadily as the effects of baseline retirements and load growth are partially offset by an increase in energy efficiency capacity. Prices rise sharply in FCA 16 because of a further increase in the performance penalty rate (increasing to $5,455/MWh)

[127] LEI Report, p. 14.

[128] A simple average of nominal dollars equates a dollar in 2020 with a dollar in 2025. Due to inflation over that five-year period, the dollars in 2025 will likely hold less value than the dollar did in 2020.

driving up marginal oil- and gas-fired generators' offer prices. Each case ultimately rises to the net cost of new entry at $9/kW-mo, but the scenarios with more cleared NPT capacity (net of induced retirements, if any) reach that level later.

In Scenarios 1 and 2, NPT depresses capacity prices by adding capacity and right-shifting the supply curve. The effect is more pronounced in the Northern New England capacity zone than in the rest of the system, since NNE creates local surplus capacity relative to local needs and export limits, as discussed in Section III.B. However, the price reduction is still less pronounced than in the LEI analysis due to the greater price-responsiveness of supply and greater stability of prices due to the flatter, more elastic supply curve we are modeling, as discussed in Sections III.2 and III.B.1.

In Scenario 3, capacity prices *increase* slightly because of the combination of NPT having no capacity value while other suppliers suffer lower energy revenues. Lower energy market revenues would increase the net cost of new entry for new natural gas-fired combined-cycle capacity by roughly $0.4/kW-mo.[129] This in turn would raise combined-cycles' capacity offer prices and set a higher clearing price in the later years when new capacity is needed to meet growing demand. There is little such effect in earlier years when oil-fired steam capacity and other low-utilization capacity is on the margin, as we are projecting. Low-utilization resources earn minimal net energy revenues, so their capacity offers are not very affected by changes in energy prices. We do not account for any energy-capacity offset effect in the other scenarios due to the convergence of energy prices between the Base Case and NPT Case in the later years (at that point, the NPT Case has 1,000 MW more hydro generation but 1,000 MW less combined-cycle generation, so energy prices are similar).

In addition to the scenarios discussed above, we also use sensitivity analyses to re-test NPT's impacts if a single uncertain market variable changes. We provide the basis for our reference assumptions in Section III.A.2, but acknowledge that these assumptions are uncertain. The variables we test are:

- **Annual retirements of existing resources that occur in both the Base Case and the Project Case:** Our reference assumption is 200 MW of retirements per year based on recent trends in announced oil/gas-fired retirements; we test a low case with half the retirement rate and a high case with twice the rate.
- **Offer prices of marginal oil- and gas-fired capacity:** both the average value and the slope around that value.

[129] T[redacted].

- **Average offer of marginal oil- and gas-fired capacity:** based on a review of ISO-NE data, we developed a range of values by adjusting the number of scarcity hours in our analysis of performance payments and the risk premium. We assume scarcity hours will range from 8.0 hours to 16.3 hours (compared to a central value of 11.3 hours) and the resulting average offers from marginal oil- and gas-fired capacity will range from \$6.5/kW-mo to \$8.7/kW-mo in FCA 16.[130]
- **Slope of offer curve for marginal oil- and gas-fired capacity:** We halved and doubled our reference assumption that 5,000 MW are spread over a range of +/- \$1/kW-mo, to produce a range of +/- \$0.5/kW-mo in one case and +/-\$2.0/kW-mo in the other.

- **The projected net cost of new entry of new natural gas-fired units:** We reviewed several data sources to project the future net cost of new entry, as described in Section III.A.2. We set our most likely reference value at \$9/kW-mo but identified a plausible range from \$7/kW-mo to \$12/kW-mo. The low end reflects the most recent auction clearing price that included almost 1,500 MW of new generation capacity. The high end is the top of the range ISO-NE considered in its analysis of the new demand curve design and is similar to the value LEI assumed in the later years of the timeframe they analyzed.

We adjust our base assumptions across the scenarios to identify the extent to which alternative assumptions would have a material impact on our results. Table 6 below shows the assumptions for each sensitivity case and the average capacity market savings under each assumption for Scenario 1 and Scenario 2.[131]

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130 Scarcity hours are based on analysis reported in: Fei Zeng (2016), Estimated Hours of System Operating Reserve Deficiency—Final Results: Capacity Commitment Period 2020–2021, October 13, 2016, p. 8. Available at: https://www.iso-ne.com/static-assets/documents/2016/10/PSPC10132016_A2_2020-21_Reserve_Deficiencies_Hours_Final.pdf

131 We did not test the effect of the sensitivities on Scenario 3 and 4 due to the relatively small or nonexistent capacity market impacts in these scenarios.

Table 6: Impact of Capacity Market Sensitivities on Average Capacity Price Impact (2020$/kW-mo)

Sensitivity	Assumptions Low	Assumptions Reference	Assumptions High	Scenario 1 Low	Scenario 1 Reference	Scenario 1 High	Scenario 2 Low	Scenario 2 Reference	Scenario 2 High
Assumed Non-Price Retirements	100 MW/year	**200 MW/year**	400 MW/year	-$0.7	**-$0.6**	-$0.6	-$0.4	**-$0.3**	-$0.3
Price of New Entry	$7.0/kW-mo	**$9.0/kW-mo**	$12.0/kW-mo	-$0.2	**-$0.6**	-$1.4	-$0.1	**-$0.3**	-$0.8
Dynamic De-List Bid Threshold (FCA 16 value)	$8.7/kW-mo	**$7.4/kW-mo**	$6.5/kW-mo	-$0.3	**-$0.6**	-$0.8	-$0.2	**-$0.3**	-$0.4
Range of Prices of Units near DDBT	+/-$2.0/kW-mo	**+/-$1.0/kW-mo**	+/-$0.5/kW-mo	-$0.5	**-$0.6**	-$0.6	-$0.3	**-$0.3**	-$0.4

NPT's capacity market price impacts are most sensitive to the assumptions concerning the upper and lower bound of capacity prices: the price of new entry on the high end and the offers of marginal oil- and gas-fired capacity at the low end. NPT's price impacts can be largest when there is as wide a gap as possible between the low end and high end prices. Changes in the non-price retirements and slope of the lower end of the supply curve have a relatively limited impact due to offsetting changes in the prices impacts. The most optimistic scenario occurs with the higher price of new entry ($12/kW-mo) that results in New Hampshire customer savings rising to $67 million per year. [redacted].[132]

B. Wholesale Energy Market Impacts

We find LEI's energy market analysis to be reasonable based on our review of LEI's methodology and results. The methodology used by LEI is relatively standard. At a basic level, it captures the fact that natural gas-fired generation is on the margin setting the price most of the time. The energy market price therefore depends on the natural gas price and the heat rate of the generator on the margin. The range of natural gas prices assumed by LEI is also reasonable and closely aligns with price projections by the Energy Information Administration (EIA).[133] LEI's projected

132 [redacted].

133 [redacted]

Continued on next page

market heat rates (***i.e.***, electricity prices divided by natural gas prices) are slightly higher than actual market conditions from 2013 and 2014, but not so high to warrant concern.[134]

LEI's analysis shows that hydro imports associated with NPT displace some generation at the margin, allowing a slightly more efficient generator to set the price. The effect is expected to be modest since the variable cost structure of the marginal generators is fairly uniform. LEI estimates $1.00/MWh lower average (load-weighted) energy prices with NPT than in the Base Case between 2020 and 2023.[135] Starting in 2024, energy prices start to converge between the cases as new natural gas-fired combined-cycle generators are added and produce energy in the Base Case but not the Project Case since they are not yet economic (due to lower capacity prices with NPT). By 2026, the Project Case is just starting to add combined-cycles, but it has 1,000 MW less combined-cycle capacity than the Base Case, offsetting the effect of the extra 1,000 MW hydro generation, so prices are approximately the same as in the Base Case.

We therefore find LEI's energy price impacts to be reasonable and adopt their results, but with modifications in the later years to account for the differences in the amount of baseload generation online each year in each case, consistent with our capacity market analysis.

Our Base Case analysis of the ISO-NE forward capacity market resulted in new natural gas-fired generators entering two years later than LEI estimated (mostly because we are using an updated lower load forecast and account for additional supply that entered the most recent auction). Our analysis found that new entry is likely to first occur in 2026 in the Base Case and then in 2029 in Scenario 1 and in 2027 in Scenario 2. In Scenario 3, NPT does not affect the outcome of the ISO-NE capacity auctions. Table 7 shows the total net new baseload generation capacity added in the case with NPT for LEI's analysis and for each of our scenarios, where new baseload generation capacity includes both new CCs and capacity shipped via NPT. It should be noted that since in Scenario 4 NPT would displace other comparable resources, which would also lead to (small) reductions in energy market prices, the incremental effect of NPT on energy market prices under Scenario 4 is essentially zero.

Continued from previous page

[redacted].

134 The 2019 implied market heat rates are 8,554 Btu/kWh for the LCOP/HH case and 8,787 Btu/kWh for the GPCM/MS case, which is higher than the average implied market heat rates for 2013 and 2014 of 8,100 Btu/kWh. LEI does not provide a justification for this discrepancy. LEI Report, p. 54.

135 Figure 14 of LEI's report shows that costs are similar for units in the supply stack between 10,000 MW to 25,000 MW. Average demand in 2024 is marked on the figure as 14,576 MW. LEI Report, p. 35.

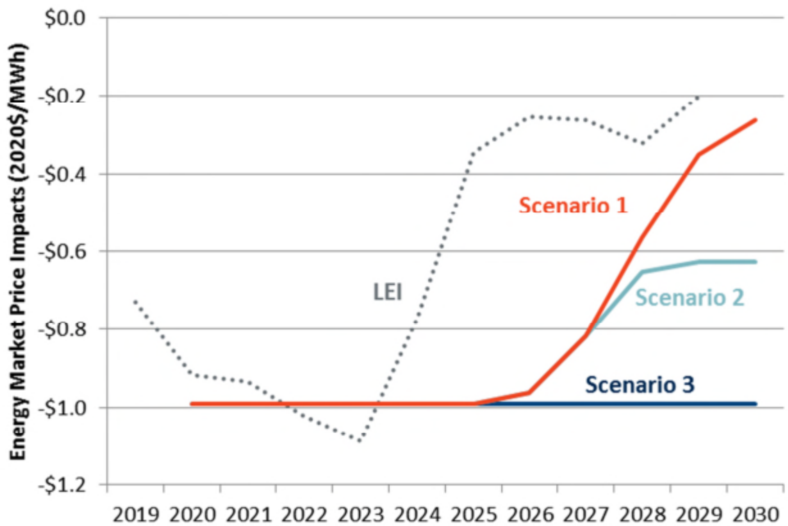
Table 7: Projected Increase in New Baseload Generation (MW)

Scenario	FCA 11 2020/21	FCA 12 2021/22	FCA 13 2022/23	FCA 14 2023/24	FCA 15 2024/25	FCA 16 2025/26	FCA 17 2026/27	FCA 18 2027/28	FCA 19 2028/29	FCA 20 2029/30	FCA 21 2030/31
LEI GPCM/MS											
Base Case (New CCs)	-	-	-	-	400	900	1,400	1,800	1,800	2,200	2,200
Project Case (New CCs + NPT)	1,000	1,000	1,000	1,000	1,000	1,000	1,400	1,800	1,800	2,200	2,200
Net New Baseload Generation	**1,000**	**1,000**	**1,000**	**1,000**	**600**	**100**	**-**	**-**	**-**	**-**	**-**
Brattle Scenario 1											
Base Case (New CCs)	-	-	-	-	-	-	94	441	791	1,144	1,500
Project Case (New CCs + NPT)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,144	1,500
Net New Baseload Generation	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**906**	**559**	**209**	**-**	**-**
Brattle Scenario 2											
Base Case (New CCs)	-	-	-	-	-	-	94	441	791	1,144	1,500
Project Case (New CCs + NPT)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,291	1,644	2,000
Net New Baseload Generation	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**906**	**559**	**500**	**500**	**500**
Brattle Scenario 3											
Base Case (New CCs)	-	-	-	-	-	-	94	441	791	1,144	1,500
Project Case (New CCs + NPT)	1,000	1,000	1,000	1,000	1,000	1,000	1,094	1,441	1,791	2,144	2,500
Net New Baseload Generation	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**

Source: LEI provided the projected capacity of new natural gas-fired CCs ("New CCs") in a June 2016 correspondence entitled "Information Requests for the LEI Report for Northern Pass."

From LEI's analysis, we find that each additional 100 MW of baseload capacity in the Project Case results in about \$0.1/MWh reduction in annual average energy prices. To project energy market benefits in Scenarios 1–3 with a different projection of when new CCs enter, we apply this value to the net baseload additions shown in Table 7 above. Based on this approach, Figure 15 below shows that the maximum energy benefits extend two years longer under our Scenario 1 then in LEI's analysis. In Scenario 2, the energy benefits remain substantial through 2030 since we assume 500 MW of NPT-induced baseload retirements are eventually replaced by new natural gas-fired combined-cycle capacity, resulting in an ongoing increase in baseload capacity. In Scenario 3, the energy market benefits do not abate because NPT continues to provide clean energy without displacing the development of any combined-cycles or other new resources, since it does not qualify or clear in the capacity market. One might argue that the impact would continue indefinitely, but we do not consider any benefits beyond 2030, since there are many ways the market could eventually adjust (*e.g.*, by pursuing fewer alternative clean resources if NPT is in place).

Figure 15: Comparison of NPT's Energy Market Price Impacts in New Hampshire



Source and notes: We use LEI's GPCM/MS case, as discussed earlier in this section. We convert all of LEI's values to 2020 dollars assuming 2% inflation. Scenario 1, 2, and 3 energy market price impacts are based on Brattle analysis.

As noted in Section II.B, these energy market estimates likely understate the benefits because they do not account for the extreme conditions not modeled regarding natural gas prices and energy market heat rates.

C. Savings for New Hampshire Electricity Customers

Given the reductions in wholesale price impacts estimated above, we estimate retail customers' savings by assuming all changes in wholesale energy and capacity prices flow through to retail customers. (See Section I.B for background on how retail rates relate to wholesale prices). The lower ***energy*** market prices translate directly to customer savings based on New Hampshire's total energy demand, which is the same in both the Base Case and Project cases. Calculating the customer savings due to lower ***capacity*** prices is complicated by the different quantities that clear the auction in the Base Case and Project Cases. In each case, we find the total capacity payments for the Northern New England load zone (Vermont, New Hampshire, and Maine) based on the applicable quantity times the zone's clearing price, then we calculate the fraction of those payments that would be borne by New Hampshire customers. The total quantity for the zone is given by ISO-NE's peak load forecast for the zone, plus 15% target reserve margin, plus the zone's peak load-ratio-share of any capacity that clears the system-wide market in excess of the Net Installed Capacity Requirement. We allocate the portion of zonal costs that New Hampshire customers must pay based on New Hampshire's peak load-ratio-share for the zone (about 45%). Finally, we make a small downward adjustment to account for customers that are not exposed to wholesale prices because they are covered by long-term contracts or self-supply.[136]

[136] This is a small adjustment, with only 4–9% of energy demand and 4–7% of peak load that are not exposed to wholesale prices. LEI Report, p. 111.

Across all of the scenarios and sensitivities we analyzed, we found that NPT could provide New Hampshire customers with retail rate savings of 0 to 0.55¢/kWh (in 2020 dollar terms) on average from 2020 to 2030. These savings are in relation to 2016 baseline retail rates of roughly 18¢/kWh. Per household, annual bill savings could be as little as zero or as great as $41.[137] Aggregating over all electricity customers in New Hampshire, annual bill savings could be between zero and $67 million, with the low end corresponding to Scenario 4 and the high end corresponding to Scenario 1 at the top of the sensitivity range on supply curve parameters. In terms of Net Present Value, these savings are worth up to $560 million based on a 7% discount rate. All of these savings metrics are shown in Table 8.

Table 8: Average Annual New Hampshire Customer Savings from 2020 to 2030

Scenarios	Energy Market Savings *$ million/year*	Capacity Market Savings *$ million/year*	Total Market Savings *$ million/year*	NPV of Market Savings *$ million*	Average Rate Impact *¢/kWh*	Average Residential Bill Savings *$/year*
Scenario 1: NPT expands the supply of clean energy and clears 1,000 MW of capacity	**$10** ($8 - $10)	**$22** ($8 - $57)	**$32** ($16 - $67)	**$284** ($153 - $560)	**0.26** (0.13 - 0.55)	**$20** ($10 - $41)
Scenario 2: Similar to Scenario 1 but NPT induces 500 MW of existing generation to retire	**$10** ($10 - $11)	**$11** ($5 - $32)	**$22** ($14 - $43)	**$197** ($134 - $371)	**0.18** (0.12 - 0.35)	**$13** ($9 - $26)
Scenario 3: NPT expands the supply of clean energy but does not provide any capacity	**$12**	**-$7**	**$5**	**$53**	**0.04**	**$3**
Scenario 4: NPT displaces competing clean energy projects	**$0**	**$0**	**$0**	**$0**	**0.00**	**$0**

Note: Values in parentheses reflect the range of sensitivity analysis results, as described in Section IV.A. All savings are expressed in 2020 dollars.

In Scenarios 1, 2, and 3, estimated customer savings from NPT's energy market price impacts are between $8 to $12 million; in Scenario 4 there is no impact since there is no net change in energy supply in that scenario.

The low range of energy market impacts across Scenarios 1, 2, and 3 is driven by the fact that energy prices are not very sensitive to changes in supply; they are more sensitive to changes in natural gas price which we assume to be unchanged with the addition of NPT. These estimates are conservatively low because they do not account for rare but extreme market conditions, including natural gas supply shortages, which could increase the energy market benefit of NPT (in Scenarios 1-3).

Capacity market impacts are potentially larger but are also much more uncertain than energy market impacts. We estimate that NPT's capacity market impacts on New Hampshire customers' annual electricity costs could range from a $57 million ***decrease*** in the best case to a $7 million cost ***increase*** in the worst. The top of the range corresponds to Scenario 1 with the upper bound assumption on the cost of new entry ($12/kW-mo). This case has the greatest benefits because it

137 We assume 621 kWh per month. U.S. Energy Information Administration (2016), 2015 Average Monthly Bill—Residential, http://www.eia.gov/electricity/sales_revenue_price/pdf/table5_a.pdf, accessed December 14, 2016.

assumes the maximum possible amount of capacity qualifies and clears, that no existing capacity retires in response, and that when NPT delays the increase of capacity prices to the level needed to attract new entry, it does so to maximum effect. NPT's suppression of capacity prices is more pronounced in the Northern New England capacity zone than in the rest of the system, creating local surplus capacity relative to local needs and export limits. However, capacity benefits fall from $57 million to $22 million by simply reducing the assumed cost of new entry to our expected value of $9/kW-month, still within Scenario 1. In Scenario 2, benefits fall to $11 million because the assumed 500 MW of permanent retirements reduces the ***net*** addition of capacity to the system to only half as much as in Scenario 1. The worst case is Scenario 3, in which NPT does not transmit any capacity into the New England market but still transmits energy and reduces energy prices; with lower energy prices, new natural gas-fired combined-cycle entrants have to earn more in the capacity market to be willing to enter the market. This sets capacity prices at a higher level in the later years than in the Base Case, raising customer costs (but not enough to fully offset the energy market benefit). Finally, in Scenario 4 there are no capacity benefits because NPT provides no more capacity than an alternative project would provide.

D. Reductions in Suppliers' Net Revenues

Reduced energy and capacity prices also reduce supplier revenues. Indeed, almost all of the savings customers would enjoy from lower prices with NPT can be considered a wealth transfer from suppliers across New England. Some of the suppliers are located in New Hampshire. In fact, New Hampshire generates more electricity than it consumes, exporting the balance, so the price impact applies to more volume of generation than load. New Hampshire suppliers will therefore tend to see a greater reduction in their revenues than the savings customers receive.[138]

Table 9 shows a proxy for the loss in suppliers' annual net revenues: the reduction in annual gross revenues for New Hampshire suppliers, which we estimate to range from $0 to $87 million per year over the 11-year time frame. To estimate changes in gross revenues, we multiplied the changes in prices by each plant's 2015 generation output and by its capacity cleared in FCA 10. ***Net*** revenues will decrease slightly less than gross revenues, since costs will decrease for any generators that exit or generate less, and since some generators may have long-term contracts that insulate them from changes in prices.

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138 For example, in 2015 total generation from New Hampshire suppliers was 20,035 GWh, compared to the projected 2016 load of 11,710 GWh.

Table 9: New Hampshire Supplier Revenue Impacts

Scenarios	11-Year Average *$ million/year*	NPV *$ million*
Scenario 1: NPT expands the supply of clean energy and clears 1,000 MW of capacity	**-$43** (-$25 to -$87)	**-$386** (-$241 to -$740)
Scenario 2: Similar to Scenario 1 but NPT induces 500 MW of existing generation to retire	**-$29** (-$20 to -$56)	**-$266** (-$193 to -$490)
Scenario 3: NPT expands the supply of clean energy but does not provide any capacity	**-$6**	**-$69**
Scenario 4: NPT displaces competing clean energy projects	**$0**	**$0**

Note: Values in parentheses reflect the range of sensitivity analysis results, as described in Section IV.A. All savings are expressed in 2020 dollars.

Table 10 shows the revenue impacts on New Hampshire suppliers by resource type in terms of the present value of reduced revenues and the levelized revenue impact. Due to its high capacity factor, the projected revenue impacts are the greatest for the Seabrook nuclear plant, ranging from $0 in Scenario 4 to $0.83/kW-mo in Scenario 1 (based on our reference value for each uncertain supply curve parameter, not the sensitivity range). Coal-fired and oil-fired generators see slightly increased revenues in Scenario 3 due to additional revenues from higher capacity prices more than offsetting their loss of revenues in the energy market.

Table 10: New Hampshire Supplier Revenue Impacts by Resource Type

		Scenario 1		Scenario 2		Scenario 3	
Resource	**Capacity** *MW*	**NPV of Revenue Impact** *2020$ million*	**Levelized Revenue Impact** *2020$/kW-mo*	**NPV of Revenue Impact** *2020$ million*	**Levelized Revenue Impact** *2020$/kW-mo*	**NPV of Revenue Impact** *2020$ million*	**Levelized Revenue Impact** *2020$/kW-mo*
Natural Gas	1,209	-$111	-$0.70	-$77	-$0.48	-$21	-$0.13
Nuclear	1,246	-$137	-$0.83	-$101	-$0.61	-$43	-$0.26
Hydro	501	-$40	-$0.61	-$25	-$0.38	-$1	-$0.01
Wind	183	-$4	-$0.17	-$4	-$0.15	-$2	-$0.10
Coal	533	-$39	-$0.55	-$24	-$0.34	$1	$0.02
Other	241	-$25	-$0.79	-$19	-$0.59	-$9	-$0.28
Oil	502	-$30	-$0.46	-$17	-$0.25	$6	$0.09
NH Total	**4,416**	**-$386**	**-$0.66**	**-$266**	**-$0.46**	**-$69**	**-$0.12**

Note: Supplier revenues do not change with the entry of NPT in Scenario 4.

V. Impacts on Greenhouse Gas Emissions

In this section, we discuss the potential impact of NPT on GHG emissions as well as how any GHG emissions reductions should be assessed in terms of their benefits to New Hampshire. At a high level, any GHG emissions reductions would be caused by providing relatively low-GHG intensive energy that would otherwise be provided by higher-emitting, mostly natural gas-fired generating sources.

Our analysis of the GHG impacts of NPT involves two steps: (1) we first assess its impact on the volume of GHG emissions (in metric tons of CO_2-equivalents); (2) we then discuss how avoided GHG emissions might be translated into a value for New Hampshire. We conclude that the value of GHG reductions depends on whether NPT is assumed to displace natural gas or other clean energy resources, on the approach for allocating reduced emissions to New Hampshire, and on the value of GHG reductions from a New Hampshire perspective.

A. Reduction in GHG Emissions

The quantity of GHG emissions reductions due to NPT differs across the four scenarios we developed above. GHG emissions reductions will be large in Scenarios 1, 2, and 3, where NPT introduces new clean energy to the New England energy market. Whenever fossil-fired generation is on the margin in the energy market, each incremental MWh of hydropower transmitted will displace GHG-intensive fossil-fired generation. The annual savings could amount to 3.4 million tons per year under Scenarios 1–3, equal to an 8% reduction of GHG emissions relative to New England's current electricity emissions.[139] However, in Scenario 4, NPT does not add incremental clean energy since it displaces other clean energy projects, so there would be no GHG savings. GHG could even increase if NPT displaces zero-emitting wind or solar power with low but non-zero-emitting hydropower.

Given that the current Hydro-Québec generation mix is predominantly hydro and new hydro facilities are currently under construction (as well as additional hydro resources or renewable resources that could be developed to meet increasing internal and external demand), it is reasonable to assume that the power flowing over NPT would likely be generated from hydro resources.[140]

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139 ISO-NE CO_2 emissions in 2014 were 39.3 MMT. ISO New England (2016), 2014 ISO New England Electric Generator Air Emissions Report, System Planning, January 2016, p. 18. Available at: https://www.iso-ne.com/static-assets/documents/2016/01/2014_emissions_report.pdf

140 [redacted]

Assuming that power flowing over NPT would be incremental hydro generation, GHG emissions from hydro resources depend on whether or not power comes from existing or new hydro resources. LEI assumed an emissions rate for the hydro resources likely to serve ISO-NE of 136 lbs/MWh, reflecting the lifecycle emissions of a new hydro resource.[141] Therefore, the results in terms of total tons of avoided GHG emissions derived by LEI seem reasonable for our first three scenarios.[142]

However, the applicants have not provided sufficient information to exclude the possibility that hydro power flowing over NPT would displace hydro power being currently supplied elsewhere, either inside the Hydro-Québec system or for current exports. If the power flowing over NPT would simply be diverting existing hydro resources from their current use, the GHG emissions impact of NPT would depend on the emissions of the resources that would take the place of the diverted hydro power.

GHG emissions reductions due to the additional hydro imports across NPT could however be substantially lower or potentially even somewhat higher than estimated by LEI. For example, emissions could be lower if NPT induces additional retirements of coal, oil, or natural gas-fired generators with higher emission rates than natural gas-fired combined-cycle units. In the current New England market, however, additional emissions reductions would be small since older coal, oil, and natural gas generation sources only produce electricity during relatively few hours of the year.[143] These resources do not emit large amounts of GHG in total, even if emissions rates are higher than those of natural gas-fired combined-cycle plants. In addition, LEI's analysis specifically found that the output of natural gas-fired combined-cycle plants decreases with the additional energy provided by NPT.[144]

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141 LEI Report, pp. 67–68.

142 The question of greenhouse gas emissions from reservoirs including hydroelectric facilities is still an active field of research. For a recent summary, see Deemer ***et al.*** (2016), Greenhouse Gas Emissions from Reservoir Water Surfaces: A New Global Synthesis, BioScience Advance Access, October 5, 2016, which cites a recent study that found that the GHG emissions from 10% of hydroelectric facilities approximate those of natural gas-fired combined-cycle turbines.

143 Over the past five years, most of New England's coal-fired generation has retired or announced plans to retire, and only the Merrimack and Schiller plants will plan to remain online after 2021. The coal plants that continue to operate have been producing a declining amount of energy due to competition with low-cost natural gas-fired generation. Correspondingly, the percentage of time coal-fired generation is marginal has decreased from 16% in 2010 to 9% in 2014. The percentage of time oil-fired generation is marginal has increased somewhat, from 3% in 2010 to 5% in 2014. See ISO New England (2016), 2014 ISO New England Electric Generator Air Emissions Report, System Planning, January 2016, Figure 4-5, page 14, and Figure 4-9, page 16. Available at: https://www.iso-ne.com/static-assets/documents/2016/01/2014_emissions_report.pdf

144 [redacted]

If, in the absence of NPT, another line transporting hydro or additional renewable resources were to be built—our Scenario 4—then NPT would have no or a negative impact on GHG emissions. Again, emissions could increase if, in the absence of NPT, the same amount of energy would otherwise be provided by non-emitting resources such as wind and solar PV, rather than hydro with some associated emissions. Even in these cases a project like NPT could change cumulative GHG emissions if it is built sooner than those alternatives.

B. VALUE OF GHG REDUCTIONS

Translating any GHG emissions avoided by NPT into a benefit for New Hampshire is complicated by both the difficulty of assessing the monetary value of a ton of avoided GHG emissions and the need to assign this value to beneficiaries. The Social Cost of Carbon (SCC) developed by the Interagency Working Group on Social Cost of Carbon of the U.S. Government and used by LEI in their analysis is highly uncertain and provides an estimate of the avoided societal cost associated with lowered GHG emissions globally.[145] The SCC however provides limited insight into society's (or New Hampshire's) willingness to pay for emissions reductions, the cost of lowering emissions, or how the value of lower GHG emissions would be allocated among stakeholders.

The uncertainty in the value of the SCC is evident in the large range of estimates of the SCC. The most recent update to the SCC finds 2020 values in a range of $12 to $123 per metric ton.[146] This range is driven by the assumed discount rate (which ranges from 2.5% to 5.0%) and whether the mean or the 95th percentile of expected costs of GHG emissions are estimated. Hence, the estimated impact on the global social cost of lowering GHG emissions by a ton differs by an order of magnitude, depending on which SCC estimate is used.

A second issue with using the SCC is related to the fact that the SCC reflects the avoided future global cost of an incremental ton of GHG emissions. Hence, while a ton of GHG avoided is indeed a global societal benefit of NPT, it is much less clear whether, or to what extent, it is a benefit to New Hampshire. In fact, since the benefits of a ton of avoided emissions are global, the fraction of the benefits flowing to New Hampshire is likely negligible.

A third issue with the SCC is that it is purely a measure of the damage of GHG emissions (and therefore the value of reducing emissions in terms of avoided damage), but says nothing about either the cost of reducing emissions or the willingness to pay for lower GHG emissions.

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145 The Interagency Working Group on Social Cost of Carbon updated the SCC in July 2015. Interagency Working Group on Social Cost of Carbon (2015), Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Revised July 2015. Available at: https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf

146 *Id.*, p. 3. The values are in 2007 dollars per metric ton of CO_2.

Therefore, the SCC is likely not a good measure of the value of a ton of avoided GHG emissions to New Hampshire.

1. Alternative Approaches to Valuing GHG reductions

However, this does not mean that the GHG benefits of NPT are zero or negligible. There are several alternative concepts to help assess the GHG benefits of NPT to New Hampshire. Apart from the SCC, a second approach to assessing the value of reduced GHG emissions is to look at the avoided costs of alternative measures to achieve similar GHG reductions that meet New Hampshire's and other New England states' GHG reduction goals. A third approach considers New Hampshire's willingness-to-pay for GHG reductions, which may not be directly observable but at least conceptually provides an upper bound to the value of reduced emissions.

Since climate change is a global issue, it is subject to the much described "commons problem." In other words, the benefits of reducing GHG emissions accrue at a global level, yet the costs of reducing emissions are incurred locally. Therefore, there is limited incentive for a small portion of the population (such as New Hampshire residents) to lower its own emissions since it would bear the costs of doing so but only receive a small share of the resulting global benefits. However, since this is true for any GHG reduction effort, this thinking results in less GHG reductions than would be beneficial to society as a whole. It has been recognized that overcoming this global commons problem requires local GHG reduction commitments shared globally. By signing the Paris Agreement, the United States has voluntarily agreed to implement policies that will reduce GHG emissions and contribute to the global effort to limit temperature increases to a maximum of two degrees Celsius.[147] Also, the Interagency Working Group's SCC estimates are used to assess U.S. policy under the National Environmental Policy Act (NEPA), providing an example at the federal level for incorporating the global societal benefits of GHG reductions into cost-benefit analyses of regulations that are intended to reduce GHG emissions more locally. Using the SCC at the local level would therefore represent an extension of the logic used by the U.S. Federal Government to use global SCC values in benefit-cost analysis related to domestic GHG abatement policies.

In general, the use of the SCC in benefit-cost analysis allows an assessment of whether the costs of GHG abatement exceed their benefit (the SCC). However, independent of such formal benefit-cost tests, many New England states have enacted legislation or executive orders that require deep decarbonization of the electricity sector by 2050 (in the context of 80% or higher economy-wide decarbonization) outside of the global climate negotiations process. Table 11 below shows the goals set by each New England state.

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[147] United Nations (2015), Adoption of the Paris Agreement, Framework Convention on Climate Change, FCCC/CP/2015/L.9/Rev. 1, Draft Decision -/CP.21, December 12, 2015. It should be noted that President-elect Donald Trump has stated an intention to withdraw from the Paris Agreement. http://www.nytimes.com/2016/11/19/us/politics/trump-climate-change.html?_r=0

Table 11: New England State Commitments to GHG Reductions

State	Action	Commitment
Connecticut	Public Act No. 08-98	2010: Equal to 1990 emissions 2020: 10% below 1990 emissions 2050: 80% below 2001 emissions
Maine	Act to Provide Leadership in Addressing the Threat of Climate Change	2010: Equal to 1990 emissions 2020: 10% below 1990 emissions Long-Term: 75-80% below 2003 emissions
Massachusetts	Global Warming Solutions Act	2020: 25% below 1990 emissions 2050: 80% below 1990 emissions
New Hampshire	New Hampshire Climate Action Plan	2025: 20% below 1990 emissions 2050: 80% below 1990 emissions
Rhode Island	RI Executive Climate Change Coordinating Council	2020: 10% below 1990 emissions 2035: 45% below 1990 emissions 2050: 80% below 1990 emissions
Vermont	Executive Order #07-05	2012: 25% below 1990 emissions 2028: 50% below 1990 emissions 2050: 75% below 1990 emissions

Source: Center for Climate and Energy Solutions (2016), State Legislation from Around the Country, http://www.c2es.org/us-states-regions/key-legislation, accessed December 14, 2016.

Given these goals, a project like NPT can be seen as contributing to achieving, or at least reducing the costs of achieving, state-level or regional decarbonization policy objectives. The cost of meeting these goals could be higher or lower than the SCC estimates referenced by LEI. If they exceed the SCC, one could conclude that the SCC is the maximum benefit from lowering GHG emissions and that incurring additional costs to reduce emissions would reduce societal value. Or one could conclude that the goals reflect valuing reduced GHG emissions in excess of the SCC, perhaps based on a different assessment of or aversion to the downside risks of climate change. Given the above discussion about the uncertainties surrounding the estimation of the SCC, it could be argued at a minimum that the full range of SCC values could be used to assess whether or not costs of lowering GHG emissions to reach policy targets or mandates are in excess of the SCC.

However, if the cost of reducing GHG emissions to some agreed-upon target is below the upper end of the range of SCC estimates, the value of reducing GHG emissions reductions attributed to a project like NPT is at most the marginal cost of reducing GHG emissions by the cheapest alternative means. This avoided cost of alternative GHG emissions reductions should also be considered the maximum value of reducing GHG emissions in the absence of a clear GHG emissions reduction target.

To summarize, to the extent New Hampshire's commitments to lowering GHG emissions are deemed to be legally binding, it would be reasonable to assume that New Hampshire values GHG emissions reductions (at least) as highly as the cost of reaching its goals, even if this cost is higher than the range of SCC estimates.[148] In that case the avoided cost of reaching targeted GHG reductions is the correct measure for valuing GHG emissions reductions by NPT. If, on the other hand, the GHG emission reduction targets are not binding in New Hampshire, then the proper valuation metric from New Hampshire's perspective would be the lower of the cost of meeting the (non-binding) GHG reduction targets and the value New Hampshire places on GHG emissions reductions, *i.e.*, New Hampshire's willingness to pay for emissions reductions.

2. Estimating the Avoided Cost of GHG Emissions Reductions

As just described, understanding the avoided cost of reducing GHG emissions is important for estimating the value of such reductions to New Hampshire. A precise calculation of these avoided costs is both complex and highly uncertain. Doing so requires assumptions about how long-term GHG reduction goals would be met with and without NPT or, without consideration of binding quantity targets, the alternative costs of reducing GHG emissions. We therefore based our analysis on a relatively simple and transparent approach to derive a reasonable range of the avoided GHG emissions reduction costs of NPT.

Our simple approach involves answering the question of what incremental "carbon support" payment, in dollars per metric ton or dollars per MWh, would be needed to achieve equivalent GHG emissions reductions as NPT. We assume, based on statements made by LEI during the technical sessions, that the incremental cost of achieving GHG reductions via NPT to be zero since the shippers on NPT are assumed to be price takers in both energy and capacity markets (*i.e.*, they are not asking for additional payments to compensate for the low-carbon content of the energy delivered over the line). Also, we ask this question over the same 11-year time horizon as LEI considered, since GHG emissions reductions at later times would result in different cumulative emissions reductions and thus further complicate the analysis.

We first assessed the technologies that could and likely would be used to replace emissions reductions provided by NPT. We then assessed their costs relative to expected market revenues and hence the amount of incremental payments that would be needed to make such alternative emissions reductions economically viable.

In New England there are essentially three technologies that could provide alternative GHG emissions reductions: onshore wind, offshore wind, and solar PV.[149] All three qualify as Class I

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148 New Hampshire's GHG reduction targets were established through the New Hampshire Climate Action Plan, which was the result of a gubernatorial task force and has not been converted into binding New Hampshire state law. Even though state laws can always be changed by subsequent legislatures, it is likely that the NH Climate Action Plan is somewhat less "legally binding" than similar targets implemented in other states through legislative processes.

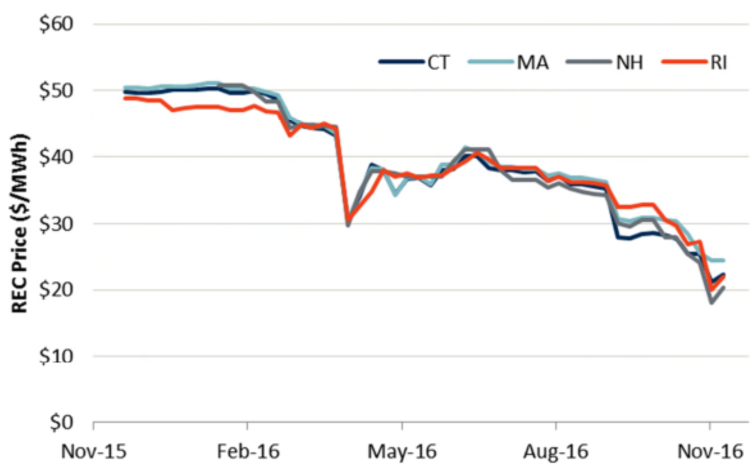
149 We ignore biomass as a fourth alternative, given the sharp reduction in incremental biomass projects following the complex discussions of avoided GHG emissions from biomass projects. We also ignore

Continued on next page

Renewable energy in all New England states with an RPS. Consequently, assuming a liquid market for Renewable Energy Certificates (REC), REC prices provide a near-term indicator of the incremental revenue support needed by Class I renewables to enter the market.[150]

Relying on REC prices has several weaknesses. First, prices are often capped by an alternative compliance payment (ACP). While the ACP is helpful in providing some potential information with respect to a state's willingness to pay for carbon emissions reductions, a REC price equal to the ACP does not mean that the ACP is sufficient to attract emissions abatement. Also, publicly-available REC prices tend to be spot prices and as such are very volatile, depending on the short term relationship between total demand for RECs to comply with the RPS and short-term supply of RECs. Figure 16 below shows New England REC prices over the past year. It is unclear whether the decline from about \$50/MWh to about \$25/MWh reflects the short-term market dynamics just discussed or changes to both electricity market prices and technology costs that have been lowering the REC price needed to attract incremental investment.

Figure 16: New England REC Prices



Source: SNL Financial, accessed 11/16/16.

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landfill gas and small hydro projects by assuming that economically attractive projects would be or have been pursued in the absence of NPT and in that sense are not "marginal" or incremental. We focus on marginal emissions reduction approaches, ***i.e.***, those that would be needed if and only if NPT were not constructed. We therefore also ignore potentially lower-cost GHG abatement approaches such as energy efficiency and the few remaining opportunities for fuel switching as remaining high-emitting fossil generation is retired, in essence because we would assume they would be implemented with and without NPT.

150 RECs are generated by qualifying facilities for each MWh of electricity generated. REC prices can be translated into equivalent carbon prices by using the assumed carbon emissions rate of the resources displaced by NPT (or the equivalent alternative resources).

We therefore also use estimates of the current costs of the three technologies described above to derive a reasonable estimate of a long-term REC-style payment that would be necessary to make each technology economical.

There is some information about the current cost of onshore wind projects in New England from publicly-available data on recent wind procurements under long-term contracts.[151] Based on these contracts, the levelized cost of energy (LCOE) of typical New England onshore wind projects is in the range of $65 to $80/MWh, while still benefitting from a federal production tax credit (PTC). Without the PTC, levelized costs would increase by $10 to $23/MWh.[152] Over the next few years, costs could decrease due to ongoing technological progress. Costs could also increase if the best wind sites are already occupied and if transmission upgrades are necessary to access other high quality wind resources.

There is still very little empirical evidence on the cost of offshore wind in New England. The only current project, a small-scale, first-of-a-kind project in New England, will be operating with a contract of $244/MWh, while likely also benefitting from a 30% investment tax credit.[153] On the other hand, the most recent offshore wind projects in Europe were able to offer electricity at a price approaching $50/MWh.[154] While it is essentially impossible to predict the cost of offshore wind projects in the region for 2020 and beyond, it is reasonable to assume that it will lie between the costs of the small Deepwater Wind project in Rhode Island and the current cost of offshore wind in Europe. On the other hand, replacing NPT with offshore wind would allow building offshore wind at a scale substantially larger than the six turbine 30 MW Rhode Island

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151 The most recent onshore wind contract signed in New England was for the Number Nine Wind Farm by Connecticut utilities. The contract price was $69/MWh, split between $57/MWh for the energy and $12/MWh for the RECs. Available at: http://www.dpuc.state.ct.us/dockcurr.nsf/(Web+Main+View/All+Dockets)?OpenView&StartKey=13-09-19. The 2015 Wind Technologies Market Report from the U.S. Department of Energy shows that the most recent contracts prices in the Northeast have been in the range of $60/MWh. Ryan Wiser and Mark Bolinger (2016), ***2015 Wind Technologies Market Report***, August 2016, p. 63. Available at: https://energy.gov/sites/prod/files/2016/08/f33/2015-Wind-Technologies-Market-Report-08162016.pdf.

152 The impact of the production tax credit on wind contracts depends on the amount of available tax equity. For more information, see: https://emp.lbl.gov/sites/all/files/lbnl-6610e_1.pdf

153 State of Rhode Island and Providence Plantations Public Utility Commission (2010), Report and Order, In Re: Review of Amended Power Purchase Agreement between Narragansett Electric Company D/B/A National Grid and Deepwater Wind Block Island, LLC pursuant to R.I. Gen. Laws § 39-26.1-7, Docket No. 4185, Written Decision August 16, 2010.

154 Vattenfall AB (2016), "Vattenfall wins tender to build the largest wind farm in the Nordics," Press Release, November 9, 2016. Available at https://corporate.vattenfall.com/press-and-media/press-releases/2016/vattenfall-wins-tender-to-build-the-largest-wind-farm-in-the-nordics/

project, which would likely provide room for substantial cost reductions.[155] In short, it seems likely that the costs of offshore wind in the 2020–2030 time frame, for which we assess GHG benefits of NPT, would exceed the cost of onshore wind projects delivering the same GHG benefits.

Finally, solar PV costs in New England are still quite high as well. Current deployment takes place primarily in response to mandates that provide payments in excess of wholesale market prices, such as Solar RECs of approximately $200/MWh for ten years plus avoided retail electricity prices of similar magnitude for behind the meter or community solar projects. Therefore, it is reasonable to assume that for the foreseeable future solar PV projects will have a cost per MWh or ton of GHG emissions reductions at least as high as onshore wind.

We have therefore decided to base our estimate of the cost of reducing GHG emissions avoided by NPT on the cost of onshore wind and the estimated support payment (in addition to energy market payments) needed to make onshore wind projects economical. Using the New England market emissions rate of 700 to 1,000 lbs/MWh assumed by LEI,[156] we can translate the recently observed REC prices and the likely range of long-term REC-type support needed for onshore wind into an equivalent range of carbon values of $40 to $100 per avoided metric ton of CO_2, as shown in Table 12.

Table 12: Estimated Cost of Avoided CO_2 for Onshore Wind

Component	Units	Low	High
Levelized Cost w/o PTC	$/MWh	$80	$100
Energy & Capacity Revenues	$/MWh	$60	$50
REC Price	$/MWh	$20	$50
Avoided Emissions	ton/MWh	0.50	0.50
Cost of Avoided CO2	**$/ton**	**$40**	**$100**

Based on this relatively simple analysis of potential alternative GHG reduction measures that may be needed in the absence of NPT, the value of avoided GHG emissions used by LEI ($79/ton in 2025) is squarely within the range of GHG abatement costs avoided by NPT. For this reason, the value per ton of GHG emissions reductions used by LEI is likely a reasonable approximation, given the relative uncertainty of the cost of GHG abatement that would be necessary in the absence of NPT.

155 For a discussion of offshore wind cost reduction pathways including economies of scale, see: E.C. Harris (2012), Offshore Wind Cost Reduction Pathways: Supply Chain Work Stream, May 2012.

156 LEI Report, p. 68.

3. Incidence of Value on New Hampshire

A final complex issue relates to how a societal value of avoided GHG emissions might be applied to New Hampshire rate payers. The methodology for estimating the benefits of GHG reductions assumes society (in our case all of New England) as the relevant beneficiary. In reality, whether this benefit is realized and how much of this benefit accrues to New Hampshire (or even more specifically to New Hampshire customers) again depends on the perspective taken. Since New Hampshire is part of the Regional Greenhouse Gas Initiative (RGGI), GHG emissions reductions by NPT will likely affect New Hampshire customers most directly through RGGI.

RGGI is a regional market-based program to reduce greenhouse gas emissions. The nine participating states, Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont use RGGI to cap and reduce CO_2 emissions from the power sector through a cap-and-trade program. The 2014 cap was set at 91 million short tons and declines by 2.5% per year through 2020.[157]

Even though LEI did not investigate any potential impact of NPT on RGGI, it is conceivable that NPT could lower RGGI prices, assuming RGGI will be in place after 2020. Assuming no changes to the RGGI Model Rule, any GHG reductions by NPT would make it easier, ***ceteris paribus***, to meet currently established RGGI emissions reduction goals. This in turn could lead to a reduction of the price of allowances under RGGI. Lower RGGI allowance prices would have two effects: They would likely lead to additional reductions in energy market prices (beyond those analyzed by LEI and ourselves), which in turn would provide energy market benefits to New England consumers. However, lower RGGI allowance prices would mean that revenues collected from auctioning off RGGI allowances, which tend to be used in ways that benefit consumers directly or indirectly, would also decline. Since some New England power generation is already carbon-free, lower RGGI allowance revenues would only partially mitigate the impact on energy prices.

However, there are two important caveats that make it prudent not to count on RGGI-related benefits of NPT. First, RGGI prices have a price floor, implemented through a reserve auction price, which increases by 2.5% per year. This floor limits how much RGGI allowance prices could drop as a result of NPT-related GHG emissions reductions. The most recent RGGI auction, Auction 34, cleared at a price of \$3.55/ton, only \$1.45 above the reserve price of \$2.10.[158] This means that the maximum impact of NPT on the auction price in this case would have been \$1.45.

Second, it is possible that the addition of NPT would not change the auction clearing prices and hence would not have any impact on allowance prices, even under current rules. Whether or not

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157 For a program description, see www.rggi.org. As of now, it is somewhat unclear how RGGI will evolve post-2020, when NPT would be online.

158 See RGGI Inc., Market Monitor Report for Auction 34; prepared by Potomac Economics, December 9, 2016.

there would be an impact of NPT depends on the shape of the bid curve submitted by participants in the auction. In Auction 34, the average bid price was $3.46 and the median bid price was $3.40. While inconclusive, this suggests that it is at least possible that there were many bids clustered around the same value, in other words that the bid curve was relatively "flat" or elastic. A flat or elastic bid curve in turn suggests that market clearing prices may not change very much in response to increasing or decreasing demand for allowance. A flat bid curve can be caused by the possibility that the technology needed to provide marginal GHG abatement is identical across a wide range of GHG emissions reductions.

In the longer run, RGGI, as currently implemented, will not by itself require GHG emissions reductions in line with the long-term mandates of many RGGI members. Consequently, it is possible that the RGGI cap, ***i.e.***, the number of allowances issued in any given year, will be adjusted downward over time. When the states reconsider the cap, the presence of projects like NPT could allow them to tighten it further than they otherwise would, with the result of RGGI prices ultimately being unaffected by a project like NPT. Put more simply, if NPT removed approximately 3 million tons of GHG emissions per year and the RGGI cap was reduced by 3 million tons per year, there would be no impact of NPT on RGGI prices. That adjustments to RGGI are possible is demonstrated by the fact that a major revision of the RGGI Model Rule was implemented for the years 2014 and forward.[159]

The above discussion illustrates that even though GHG reductions due to NPT would benefit New England overall—in the sense of contributing to meeting long-term GHG reduction goals and/or to doing so at a lower cost than alternative approaches—it is possible that these benefits would not flow through to customers, but rather be captured by the producers of low- or non-emitting energy producers, such as the sellers of hydro power over NPT in the form of higher electricity prices. Moreover, it is not yet clear whether the region will continue to use cap-and-trade or alternative approaches to meeting long-term GHG emissions reduction goals.

Since the benefits of GHG reductions will likely at least partially flow to the providers of low carbon energy and other parties to a project such as NPT, consumers such as New Hampshire customers are unlikely to capture the full benefit of the lower total cost of reducing GHG emissions. In any case, it would not be appropriate to count the full amount of NPT's carbon abatement as a benefit for New Hampshire since emissions reductions occur on a regional basis and since contractual arrangements could allocate GHG benefits to different states. Hydro-Québec is offering Public Service of New Hampshire (PSNH) a power purchase agreement via NPT that would provide PSNH about 10% of the power flowing over NPT at the New England energy market price and would include the associated environmental attributes. Under this arrangement, it would be appropriate to allocate 10% or $14 to $34 million annually of the GHG benefits of NPT to New Hampshire. Assuming an installed cost of $3/Watt for solar PV (representative of a mix of residential and larger scale installed costs today), this benefit would be

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[159] See https://www.rggi.org/ for a description of the model rule changes.

equivalent to the cost of about 5-11 MW of new solar PV capacity installed each year, or about 1,000 to 2,000 new solar roofs of 5 kW installed each year.

These benefits could apply even in our Scenario 4, where NPT and the agreement with PSNH occur instead of a competing project with which PSNH does not have a special agreement. Alternatively, if the PSNH agreement does not go forward, the rights to clean energy might be assigned entirely to parties outside New Hampshire, and New Hampshire would enjoy no GHG reduction credit.

Again depending on how specifically GHG reduction goals are achieved (carbon price, cap and trade, *etc.*), there could be additional costs to New Hampshire. For example, under a cap-and-trade program with fixed GHG reduction goals, a project like NPT could displace more expensive renewable projects that would otherwise contribute the needed GHG reductions, as described above. If some of these projects would be located in New Hampshire, GHG reductions achieved through NPT might displace renewable projects in New Hampshire as well as the economic benefits associated with them.[160]

In summary, estimating the overall impact of reduced GHG emissions on New Hampshire consumers depends significantly on the regulatory framework under which future emissions reductions in New Hampshire and the region will be accomplished, in addition to the technology mix that would be used to achieve any emissions reductions, with or without NPT. Given the tremendous uncertainties associated with each of these issues, we conclude, like LEI, that any attempt to further allocate emissions reductions benefits to individual stakeholder groups in New Hampshire would be speculative.

160 To be attributable to GHG reductions, such projects would have to be viable only due to GHG reduction efforts and not otherwise be built in the absence of NPT, in which case the economic impacts on New Hampshire would already be included in our scenarios discussed above.

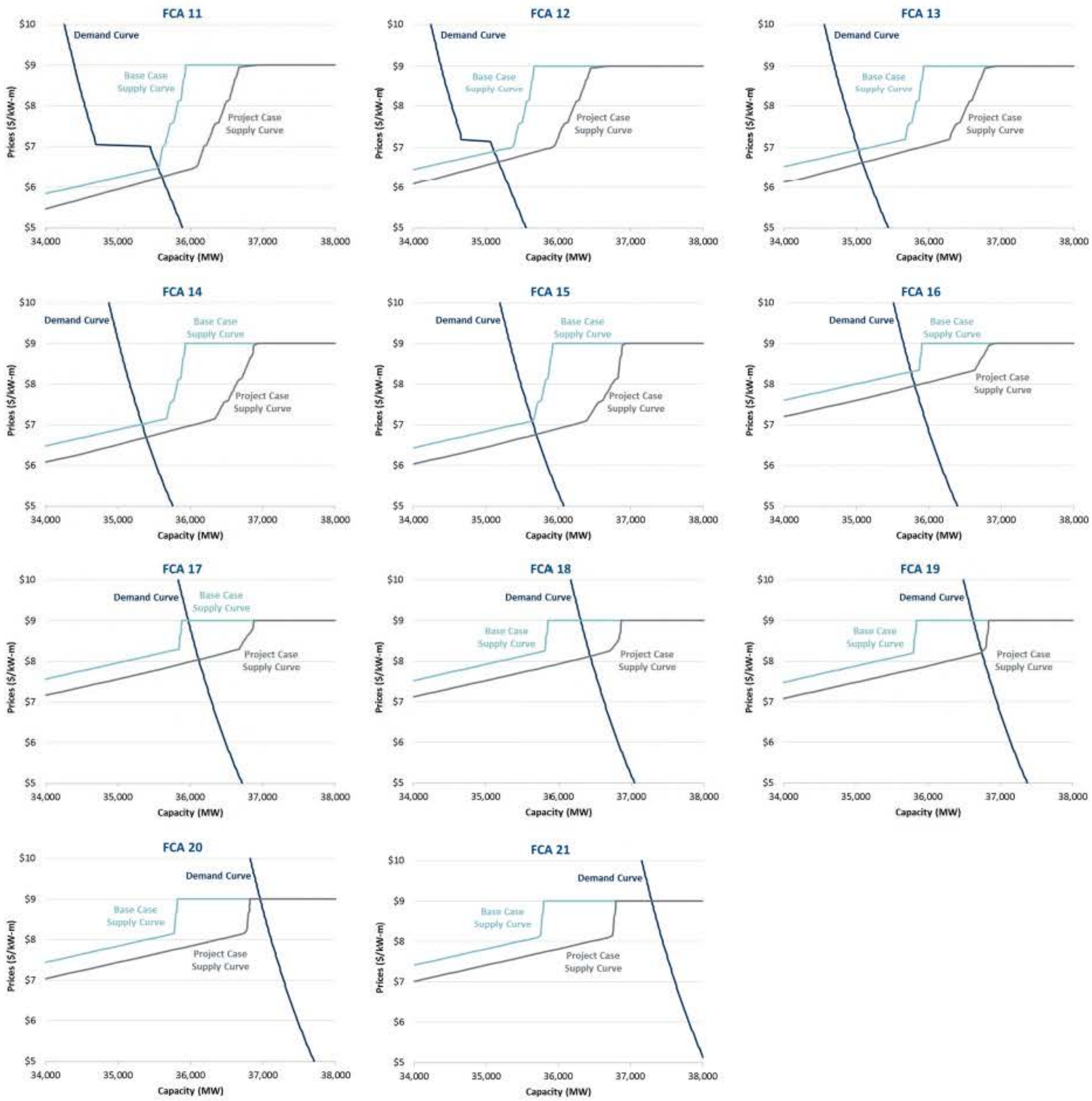
Appendix A. Glossary of Acronyms

Acronym	Definition	Description
CC	Combined-cycle	Generating unit that utilizes combustion turbine and steam turbine, most often fueled by natural gas
CO_2	Carbon dioxide	Greenhouse gas emitted by combustion of fossil fuels
CONE	Cost of New Entry	Price at which new units are projected to enter the market
CT	Combustion turbine	Type of generation plant that has relatively low capital costs but high variable costs and is most often operated during peak load hours
DDBT	Dynamic Delist Bid Threshold	The price threshold that determines whether the ISO New England Internal Market Monitor reviews offers from existing units for supply-side market power mitigation
FCA	Forward Capacity Auction	Annual auctions for capacity administered by ISO New England that procure capacity three years ahead of the capacity commitment period
FCM	Forward Capacity Market	ISO New England's wholesale capacity market
GHG	Greenhouse gas	Carbon dioxide, methane, or any other gas contributing to climate change
HQICC	Hydro-Québec Interconnection Capacity Credits	Capacity credits assigned to owners of rights to the Phase II transmission line from Quebec to New England
ISO-NE	ISO New England	ISO New England operates the power system in New England and administers the wholesale energy and capacity markets
kW	Kilowatt	Unit of power
kWh	Kilowatt-hour	Unit of energy; average monthly New Hampshire bill is 621 kilowatt-hours
kW-mo	Kilowatt-month	Unit of capacity per month
LEI	London Economics, Inc	Consulting firm that submitted an expert report on behalf of Applicants
MRI	Marginal Reliability Impact	New capacity demand curves used in ISO New England
MW	Megawatt	Unit of power equal to 1,000 kilowatts
MWh	Megawatt-hour	Unit of energy equal to 1,000 kilowatt-hours
NECPL	New England Clean Power Link	Proposed transmission project from Québec to Vermont

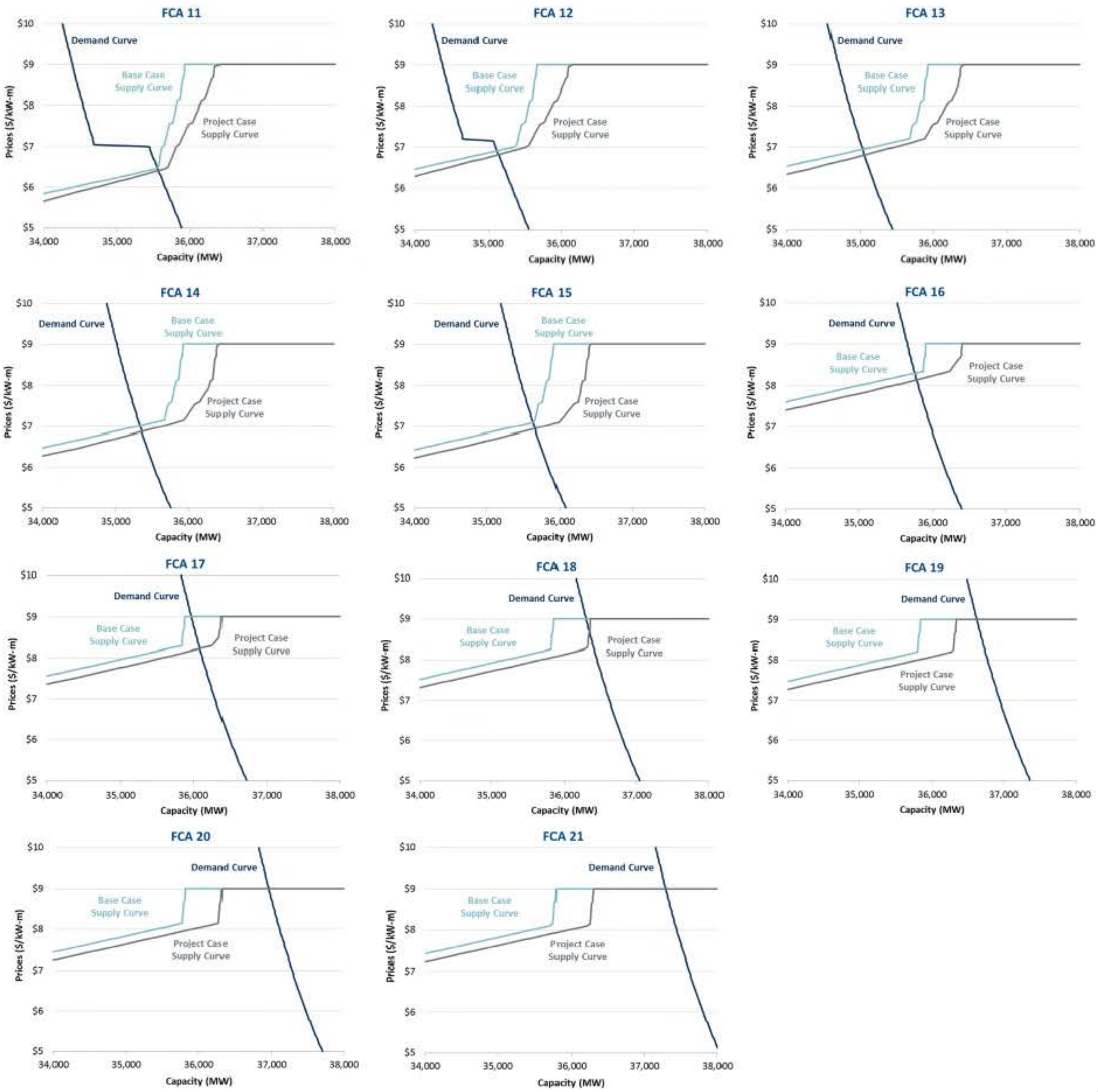
Acronym	Definition	Description
NICR	Net Installed Capacity Requirement	Reliability requirement for capacity
NNE	Northern New England	Export constrained zone within ISO New England system
NPT	Northern Pass Transmission	The transmission line proposed by Applicants to be built in New Hampshire
PJM	PJM Interconnection LLC	Regional transmission organization in the eastern United States
PSNH	Public Service of New Hampshire	The largest New Hampshire electric utility; also serves as a retail electric provider
PV	Photovoltaic	A device that generates energy from sunlight
REC	Renewable Energy Certificates	Certificate for renewable energy that can be bought and sold; incentivizes renewable energy sources
RGGI	Regional Greenhouse Gas Initiative	A multi-state cap-and-trade program to reduce greenhouse gas emissions
RPS	Renewable Portfolio Standards	State-level mandates that certain percentages of energy be generated from renewable sources
SCC	Social cost of carbon	An estimate of the global marginal social cost of a metric ton of carbon dioxide emissions

Appendix B. Capacity Market Clearing Results

A. Scenario 1



B. Scenario 2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Demand Curve
Base Case Supply Curve
Project Case Supply Curve
FCA 12
Demand Curve
Base Case Supply Curve
Project Case Supply Curve
FCA 13
Demand Curve
Base Case Supply Curve
Project Case Supply Curve
FCA 14
Demand Curve
Base Case Supply Curve
Project Case Supply Curve
FCA 15
Demand Curve
Base Case Supply Curve
Project Case Supply Curve
FCA 16
Demand Curve
Base Case Supply Curve
Project Case Supply Curve
FCA 17
Demand Curve
Base Case Supply Curve
Project Case Supply Curve
FCA 18
Demand Curve
Base Case Supply Curve
Project Case Supply Curve
FCA 19
Demand Curve
Base Case Supply Curve
Project Case Supply Curve
FCA 20
Demand Curve
Base Case Supply Curve
Project Case Supply Curve
FCA 21
Demand Curve
Base Case Supply Curve
Project Case Supply Curve
Prices ($/kW-m)
Capacity (MW)
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$8
$7
$6
$5
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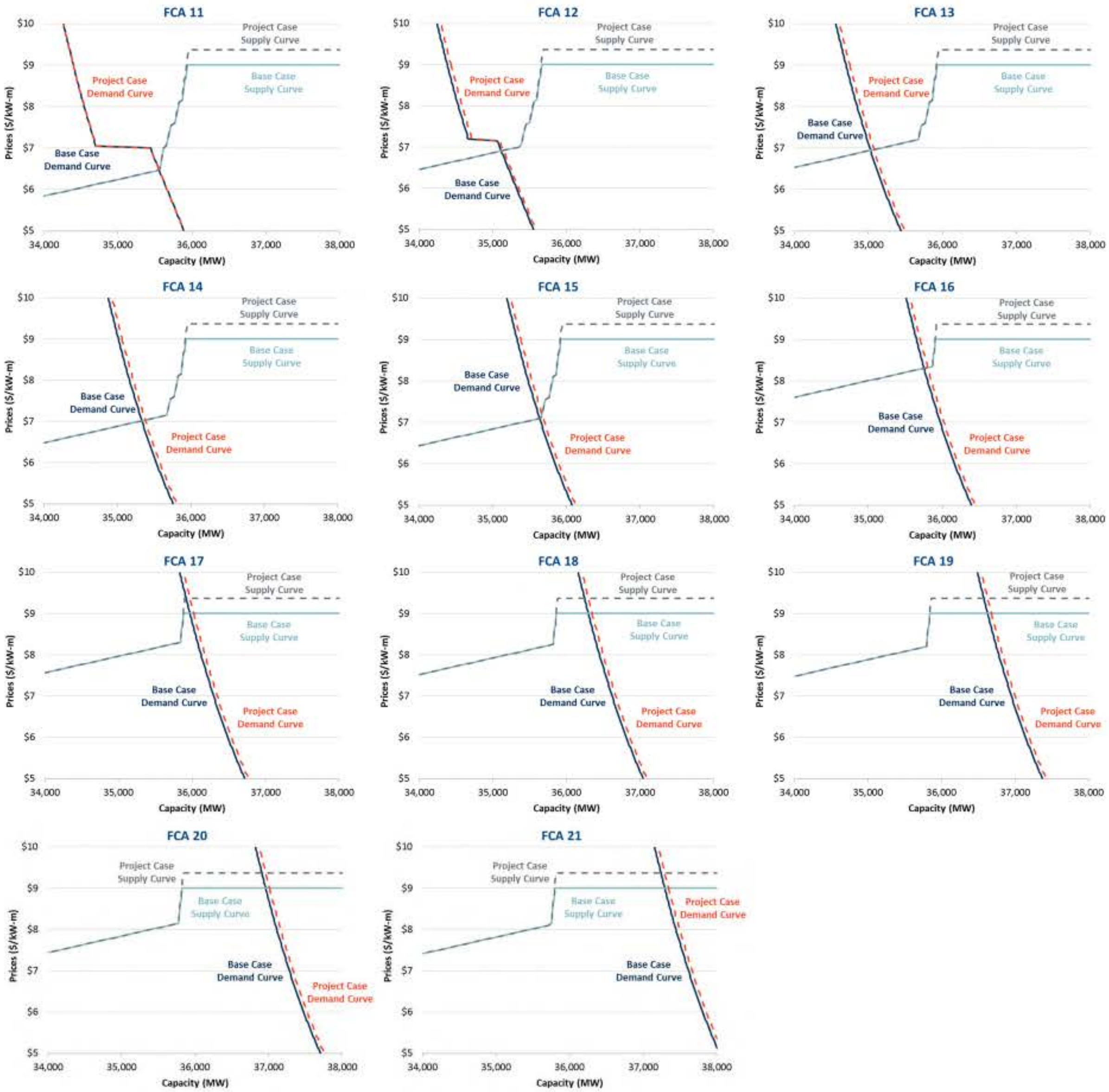
35,000
36,000
37,000
38,000

C. SCENARIO 3


FCA 11
FCA 12
FCA 13
FCA 14
FCA 15
FCA 16
FCA 17
FCA 18
FCA 19
FCA 20
FCA 21
Project Case Supply Curve
Base Case Supply Curve
Project Case Demand Curve
Base Case Demand Curve
Prices ($/kW-m)
$10
$9
$8
$7
$6
$5
Capacity (MW)
34,000
35,000
36,000
37,000
38,000

CAMBRIDGE
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SAN FRANCISCO
WASHINGTON
TORONTO
LONDON
MADRID
ROME
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